UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

North American Electric Reliability Corporation	))	**Docket No. __________**

PETITION OF THE
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION
FOR APPROVAL OF PROPOSED RELIABILITY STANDARD PRC-005-4

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Pursuant to Section 215(d)(1) of the Federal Power Act ("FPA")[1] and Section 39.5[2] of the Federal Energy Regulatory Commission's ("FERC" or "Commission") regulations, the North American Electric Reliability Corporation ("NERC")[3] hereby submits for Commission approval:

- proposed Reliability Standard PRC-005-4 (Protection System, Automatic Reclosing, and Sudden Pressure Relaying Maintenance) (Exhibit A);
- one new (Sudden Pressure Relaying) and four revised definitions (Protection System Maintenance Program, Component Type, Component, and Countable Event);[4]
- the implementation plan for proposed Reliability Standard PRC-005-4 ("Implementation Plan") (Exhibit B); and
- the Violation Risk Factors ("VRFs") and the revised Violation Severity Levels ("VSLs") for proposed PRC-005-4 (Exhibits A and G).

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1 16 U.S.C. § 824o (2012).

2 18 C.F.R. § 39.5 (2014).

3 The Commission certified NERC as the electric reliability organization ("ERO") in accordance with Section 215 of the FPA on July 20, 2006. *N. Am. Elec. Reliability Corp.*, 116 FERC ¶ 61,062 (2006).

4 These terms were approved as PRC-005 specific definitions along with the approval of Reliability Standard PRC-005-2. *See Protection System Maintenance Reliability Standard*, Order No. 793, 145 FERC ¶ 61,253 (2013). The definitions can be found in the posted PRC-005-2 Reliability Standard. Once approved, the revised versions of the definitions will be located in the posted version of proposed PRC-005-4.

NERC requests that the Commission approve the proposed Reliability Standard, and find that it is just, reasonable, not unduly discriminatory or preferential, and in the public interest.[5] NERC also requests approval of the retirement of Reliability Standard PRC-005-3 as detailed in the Implementation Plan. NERC notes that proposed Reliability Standard PRC-005-4 builds on the prior version, PRC-005-3, which is pending approval with the Commission.[6]

As required by Section 39.5(a)[7] of the Commission's regulations, this petition presents the technical basis and purpose of proposed Reliability Standard PRC-005-4, a summary of the development history (Exhibit H), and a demonstration that the proposed Reliability Standard meets the criteria identified by the Commission in Order No. 672[8] (Exhibit C). Proposed Reliability Standard PRC-005-4 was adopted by the NERC Board of Trustees ("Board") on November 13, 2014.

In addition to proposed version 4, NERC is separately filing limited revisions to PRC-005-2 and proposed PRC-005-3, which have been developed in two other NERC Projects. In Project 2014-01 – Standards Applicability for Dispersed Generation Resources, NERC developed changes to the applicability section of version 2 and version 3 of PRC-005 to ensure that the Generator Owners and Generator Operators of dispersed power producing resources are appropriately assigned responsibility in certain Reliability Standards in light of the new definition of Bulk Electric System. These changes are separate from the current proposed

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5 Unless otherwise designated, all capitalized terms shall have the meaning set forth in the *Glossary of Terms Used in NERC Reliability Standards*, *available at* http://www.nerc.com/files/Glossary_of_Terms.pdf

6 *See* NERC Feb. 14, 2014 Petition, Docket No. RM14-8-000. *See also Notice of Proposed Rulemaking, Protection System Maintenance Reliability Standard*, 148 FERC ¶ 61,041 (2014) ("PRC-005-3 NOPR")

7 18 C.F.R. § 39.5(a) (2013).

8 The Commission specified in Order No. 672 certain general factors it would consider when assessing whether a particular Reliability Standard is just and reasonable. *See Rules Concerning Certification of the Electric Reliability Organization; and Procedures for the Establishment, Approval, and Enforcement of Electric Reliability Standards*, Order No. 672, FERC Stats. & Regs. ¶ 31,204, at P 262, 321-37, *order on reh'g*, Order No. 672-A, FERC Stats. & Regs. ¶ 31,212 (2006).

changes in proposed PRC-005-4. Corresponding changes to proposed PRC-005-4 to align the changes developed in Project 2014-01 are currently being developed by NERC. NERC anticipates that these changes will be submitted for approval to the NERC Board in February of 2015 and subsequently submitted to the Commission for approval in a separate petition.

NERC has also developed changes to version 2 and version 3 of PRC-005 in Project 2010-05.2 "Phase 2 of Special Protection Systems" to replace the use of "Special Protection System" with the defined term "Remedial Action Scheme." These two terms share a common definition in the NERC Glossary. These changes were developed in anticipation of the development of a revised definition of "Remedial Action Scheme," which is the subject of a separate NERC Petition. Proposed PRC-005-4 includes this change to the use of "Remedial Action Scheme." These changes are also independent of this Petition.

NERC has coordinated the implementation timing and adjusted the NERC numbering convention to provide for proper sequencing of changes. In summary, the Commission can act on this Petition separately. NERC is not requesting that the Commission coordinate the timing of this Petition with any other upcoming Petitions.

I. EXECUTIVE SUMMARY

To satisfy NERC's commitment to develop modifications to PRC-005 in response to Order No. 758,[9] the proposed Reliability Standard PRC-005-4 adds "Sudden Pressure Relaying" that can affect the reliable operation of the Bulk-Power System to the applicability of Reliability Standard PRC-005. Sudden pressure relays are designed to quickly detect faults on Bulk-Power System transformer equipment that may remain undetected by other Protection Systems, and can operate to limit any potential damage on the equipment. Potential misoperation of sudden

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[9] *Interpretation of Protection System Reliability Standard*, Order No. 758, 138 FERC ¶ 61,094 ("Order No. 758"), *order on reh'g*, 139 FERC ¶ 61,227 (2012).

pressure relays that initiate tripping in response to fault conditions can impact the reliability of the Bulk-Power System. As a result of the addition of Sudden Pressure Relaying in proposed PRC-005-4, applicable entities will be obligated to document and implement programs for the maintenance of applicable sudden pressure relays affecting the reliability of the Bulk Electric System so that the equipment is kept in working order.

In the Notice of Proposed Rulemaking ("NOPR")[10] preceding Order No. 758, the Commission noted a concern that NERC's proposed interpretation of PRC-005-1 may not include all components that serve in some protective capacity.[11] The Commission proposed to direct NERC to develop a modification to the Reliability Standard to include "any component or device that is designed to detect defective lines or apparatuses or other power system conditions of an abnormal or dangerous nature and to initiate appropriate control circuit actions."[12] NERC commented that the proposed directive was overly broad and proposed an alternative, which was accepted by the Commission to provide technical analysis that describes the devices and functions (to include sudden pressure relays which trip for fault conditions) to address the Commission's concerns, and propose minimum maintenance activities and maximum maintenance intervals for such devices. The Commission directed NERC to submit a schedule for the development of the technical document and standards development work that resulted from the report recommendations.

In response to Order No. 758, the NERC System Protection and Control Subcommittee ("SPCS") performed a technical study to determine which devices that respond to non-electrical quantities should be addressed within PRC-005 identified devices ("SPCS Report") (Exhibit

[10] *Interpretation of Protection System Reliability Standard*, Notice of Proposed Rulemaking, 133 FERC ¶ 61,223 (2010) ("Interpretation NOPR").
[11] *Id.* at P 11.
[12] *Id.*

D).[13] The standard drafting team developed revisions to Reliability Standard PRC-005-3 in line with the SPCS Report recommendations.

II. NOTICES AND COMMUNICATIONS

Notices and communications with respect to this filing may be addressed to the following:[14]

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III. BACKGROUND

A. Regulatory Framework

By enacting the Energy Policy Act of 2005,[15] Congress entrusted the Commission with the duties of approving and enforcing rules to ensure the reliability of the Nation's Bulk-Power System, and with the duties of certifying an ERO that would be charged with developing and enforcing mandatory Reliability Standards, subject to Commission approval. Section 215(b)(1)[16]

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[13] NERC Petition, Ex. D, *Sudden Pressure Relays and Other Devices that Respond to Non-Electrical Quantities: SPCS Input for Standard Development in Response to FERC Order No. 758*, NERC SPCS (Dec. 2013).

[14] Persons to be included on the Commission's service list are identified by an asterisk. NERC respectfully requests a waiver of Rule 203 of the Commission's regulations, 18 C.F.R. § 385.203 (2013), to allow the inclusion of more than two persons on the service list in this proceeding.

[15] 16 U.S.C. § 824o (2012).

[16] *Id.* § 824(b)(1).

of the FPA states that all users, owners, and operators of the Bulk-Power System in the United States will be subject to Commission-approved Reliability Standards. Section 215(d)(5)[17] of the FPA authorizes the Commission to order the ERO to submit a new or modified Reliability Standard. Section 39.5(a)[18] of the Commission's regulations requires the ERO to file with the Commission for its approval each Reliability Standard that the ERO proposes should become mandatory and enforceable in the United States, and each modification to a Reliability Standard that the ERO proposes should be made effective.

The Commission has the regulatory responsibility to approve Reliability Standards that protect the reliability of the Bulk-Power System and to ensure that such Reliability Standards are just, reasonable, not unduly discriminatory or preferential, and in the public interest. Pursuant to Section 215(d)(2) of the FPA[19] and Section 39.5(c)[20] of the Commission's regulations, the Commission will give due weight to the technical expertise of the ERO with respect to the content of a Reliability Standard.

B. NERC Reliability Standards Development Procedure

The proposed Reliability Standard was developed in an open and fair manner and in accordance with the Commission-approved Reliability Standard development process.[21] NERC develops Reliability Standards in accordance with Section 300 (Reliability Standards

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17 *Id.* § 824o(d)(5).

18 18 C.F.R. § 39.5(a).

19 16 U.S.C. § 824o(d)(2).

20 18 C.F.R. § 39.5(c)(1).

21 *Rules Concerning Certification of the Electric Reliability Organization; and Procedures for the Establishment, Approval, and Enforcement of Electric Reliability Standards*, Order No. 672 at P 334, FERC Stats. & Regs. ¶ 31,204, *order on reh'g*, Order No. 672-A, FERC Stats. & Regs. ¶ 31,212 (2006) ("Further, in considering whether a proposed Reliability Standard meets the legal standard of review, we will entertain comments about whether the ERO implemented its Commission-approved Reliability Standard development process for the development of the particular proposed Reliability Standard in a proper manner, especially whether the process was open and fair. However, we caution that we will not be sympathetic to arguments by interested parties that choose, for whatever reason, not to participate in the ERO's Reliability Standard development process if it is conducted in good faith in accordance with the procedures approved by FERC.").

Development) of its Rules of Procedure and the NERC Standard Processes Manual.[22] In its order certifying NERC as the Commission's Electric Reliability Organization, the Commission found that NERC's proposed rules provide for reasonable notice and opportunity for public comment, due process, openness, and a balance of interests in developing Reliability Standards[23] and thus satisfies the criteria for approving Reliability Standards.[24] The development process is open to any person or entity with a legitimate interest in the reliability of the Bulk-Power System. NERC considers the comments of all stakeholders, and a vote of stakeholders and the NERC Board of Trustees is required to approve a Reliability Standard before the Reliability Standard is submitted to the Commission for approval.

C. History of Project 2007-17.3

In Order No. 693,[25] the Commission approved Reliability Standard PRC-005-1 and directed NERC to "develop a modification … through the Reliability Standards development process that includes a requirement that maintenance and testing of a protection system must be carried out within a maximum allowable interval that is appropriate to the type of the protection system and its impact on the reliability of the Bulk-Power System."[26] In 2007, NERC initiated Project 2007-17 Protection System Maintenance and Testing to address the Commission's directive.

While the standard drafting team was developing the necessary reliability enhancements to PRC-005, the Commission approved two interpretations of PRC-005-1. On April 15, 2011,

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22 The NERC *Rules of Procedure* are available at http://www.nerc.com/AboutNERC/Pages/Rules-of-Procedure.aspx. The NERC *Standard Processes Manual* is available at http://www.nerc.com/comm/SC/Documents/Appendix_3A_StandardsProcessesManual.pdf.

23 116 FERC ¶ 61,062 at P 250.

24 Order No. 672 at PP 268, 270.

25 *Mandatory Reliability Standards for the Bulk-Power System*, Order No. 693, FERC Stats. & Regs. ¶ 31,242 ("Order No. 693"), *order on reh'g*, Order No. 693-A, 120 FERC ¶ 61,053 (2007).

26 *Id.* at P 1475.

NERC filed a petition seeking Commission approval of an interpretation of Requirements R1 and R3 of Reliability Standard PRC-004-1 (Analysis and Mitigation of Transmission and Generation Protection System Misoperations) and Requirements R1 and R2 of Reliability Standard PRC-005-1 (Transmission and Generation Protection System Maintenance and Testing). The Commission approved NERC's interpretation, effective as of September 26, 2011.[27]

On February 3, 2012, the Commission issued Order No. 758, approving a second interpretation of PRC-005-1. In the NOPR preceding Order No. 758, the Commission noted a concern that NERC's proposed interpretation of PRC-005-1 may not include all components that serve in some protective capacity.[28] The Commission proposed to direct NERC to develop a modification to the Reliability Standard to include "any component or device that is designed to detect defective lines or apparatuses or other power system conditions of an abnormal or dangerous nature, including devices designed to sense or take action against any abnormal system condition that will affect reliable operation, and to initiate appropriate control circuit actions."[29]

NERC responded that it "understands FERC's concerns related to protective relays that do not respond to electrical quantities and agrees that sudden pressure relays which trip for fault conditions should be maintained in accordance with NERC Reliability Standard requirements."[30] NERC also commented that the proposed directive was overly broad and proposed an alternative, which was accepted by the Commission to provide technical analysis that describes the devices

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27 *N. Am. Elec. Reliability Corp.*, 136 FERC 61,208 (2011).

28 Interpretation NOPR at P 11.

29 *Id.*

30 *Comments of the North American Electric Reliability Corporation in Response to Notice of Proposed Rulemaking*, Docket No. RM10-5-000, at 6-7 (Feb. 25, 2011) ("NERC Comments").

and functions (to include sudden pressure relays which trip for fault conditions) to address the Commission's concerns, and propose minimum maintenance activities and maximum maintenance intervals for such devices. The Commission directed NERC to submit a schedule for the development of the technical document and standards development work that results from the report recommendations.

D. SPCS Report

In response to Order No. 758, the SPCS performed a technical study to determine which devices that respond to non-electrical quantities should be addressed within PRC-005 identified devices. The SPCS Report recommended that the standard drafting team modify Reliability Standard PRC-005 to:

1. explicitly address maintenance and testing of the actuator device of the sudden pressure relay when applied as a protective device that trips a facility described in the applicability section of the Reliability Standard;
2. develop minimum maintenance intervals and activities for sudden pressure relays; and
3. modify the applicable tables of the Reliability Standard to explicitly include sudden pressure control circuitry.[31]

To reach these recommendations, the SPCS considered the Commission's concerns in Order No. 758 and studied a broad range of devices that respond to non-electrical quantities to determine specifically which devices present a risk to the Bulk-Power System. To ensure the full scope of devices responding to non-electrical quantities were considered in the study, the SPCS used the list of ninety-four devices included in the IEEE Standard Electrical Power System

[31] NERC Petition, Ex. D, SPCS Report at 4.

Device Function Numbers standard as a starting point for its assessment.[32] The SPCS applied multiple layers of analysis to each device to select the ones that can affect the reliability of the Bulk-Power System, and, therefore, require maintenance and testing under PRC-005.

First, the SPCS considered what attributes of a device could affect the reliability of the Bulk-Power System[33] and created three categories of devices based on the risk these devices present to the Bulk-Power System. The SPCS concluded that only one of the three categories presented a risk to Bulk-Power System reliability that is sufficient to require maintenance and testing. This category included all devices that *initiate actions to clear faults or mitigate abnormal system conditions*.[34]

Second, the SPCS applied a two-step process to more narrowly identify the devices that should be subject to maintenance and testing. In the first step, the SPCS eliminated from the ninety-four IEEE devices the ones that were previously considered as a result of the revised definition of Protection System or those that are clearly not protective devices, such as primary equipment and control devices.[35] Following this initial screening, the SPCS developed a short list of devices that required in-depth analysis.

Finally, the SPCS grouped the devices on the short list into three categories[36] based on their function and whether the device supports the reliable operation of the Bulk-Power System.[37] Following this final analysis, the SPCS concluded that only the first category – sudden pressure relays that are utilized in a trip application – should be included within the scope of

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[32] A list of all IEEE device numbers, including a description of each device is included in Appendix B of the SPCS Report. *See* NERC Petition, Ex. D, SPCS Report at 13-20.

[33] For detailed explanation of the considerations of the risk to the reliable operations of the Bulk-Power System, *see Id.* at 7.

[34] *Id.* (emphasis added)

[35] The initial categorization of devices is documented in Appendix C of the SPCS Report. *See id.* at 25.

[36] Id. at 8. The short list of devices and the SPCS evaluation of each device are included in Appendix D of the SPCS Report. *Id.* at 37-32.

[37] *Id*. Classification of the devices on the short list is presented in Table 1 of the SPCS Report. *Id.* at 9.

PRC-005. The SPCS Report recommended that monitoring devices, and devices that initiate action in response to abnormal equipment conditions, but are not necessary for the reliable operation of the Bulk-Power System, should be excluded from the requirements of PRC-005. The SPCS recommendations for minimum maintenance activities and maximum intervals for sudden pressure relays that are utilized in a trip application are discussed in the Section IV below in the discussion of the changes to the PRC-005 Reliability Standard.

E. SPCS Supplemental Report

In response to comments and questions during the standards development process from Commission staff observers, the SPCS also revisited whether additional devices should be included to address the Commission's concern articulated in Order No. 758. Particularly, questions arose whether PRC-005 should include turbine generator vibration monitors and circuit breaker arc extinguishing systems. The SPCS issued a supplement to the SPCS Report, which provided information on events during which these devices operated or failed to operate, and concluded that the devices do not affect the reliable operation of the Bulk-Power System ("SPCS Supplemental Report").[38] The SPCS reaffirmed its original conclusion in the SPCS Report that these devices should not be included in the applicability of PRC-005.[39]

IV. <u>JUSTIFICATION FOR APPROVAL</u>

As discussed in Exhibit C and below, proposed Reliability Standard PRC-005-4 satisfies the Commission's criteria in Order No. 672 and is just, reasonable, not unduly discriminatory or preferential, and in the public interest. The enhanced proposed Reliability Standard promotes

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[38] NERC Petition, Ex. E, *Sudden Pressure Relays and Other Devices that Respond to Non-Electrical Quantities: Supplemental Information to Support Project 2007-17.3: Protection System Maintenance and Testing*, NERC SPCS (Oct. 31, 2014).

[39] For detailed explanation of the SPCS considerations related to these devices, see *SPCS Supplemental Report*, Exhibit E.

reliability by adding Sudden Pressure Relaying to the language of the Commission-approved Reliability Standard PRC-005-2, and to the pending proposed PRC-005-3, thereby extending the coverage of an entity's Protection System Maintenance Program to include Sudden Pressure Relaying Components. The purpose of proposed PRC-005-4 is to document and implement programs for the maintenance of all Protection Systems, Automatic Reclosing, and Sudden Pressure Relaying affecting the reliability of the Bulk Electric System so that they are kept in working order. Proposed PRC-005-4 adds detailed tables of minimum maintenance activities and maximum maintenance intervals for Sudden Pressure Relaying Components to the proposed PRC-005-3 Reliability Standard, extending the benefits of a strong maintenance program to these Components.

The Sudden Pressure Relaying Components included in proposed PRC-005-4 are based on the findings of the SPCS Report and SPCS Supplemental Report included as Exhibits D and E respectively. To assist responsible entities in understanding the addition of Sudden Pressure Relaying Components to PRC-005, the standard drafting team revised the *Supplementary Reference and FAQ* document (Exhibit F) developed concurrently with proposed PRC-005-4. This revised document will be posted with the proposed PRC-005-4 Reliability Standard following approval.

Proposed PRC-005-4 satisfies the Commission's concerns raised in Order No. 758 by including in the scope of Reliability Standard PRC-005 sudden pressure relays that detect fault on Bulk-Power System transformer equipment and trip in response to fault conditions, as recommended by the SPCS Report. Provided below is a summary of the recommendations from the SPCS Report, including discussion of sudden pressure relays, an overview of the modifications to Reliability Standard PRC-005-3 necessary to meet NERC's obligations stemming from Order No. 758, and a discussion of the Implementation Plan.

A. Sudden Pressure Relays

Sudden pressure relays respond to changes in pressure and are utilized as protective devices for power transformers. Sudden pressure relays can detect rapid changes in gas pressure, oil pressure, or oil flow that are indicative of faults within the transformer equipment. Sudden pressure relays can rapidly detect transformer equipment faults that could remain undetected by other Protection Systems. In addition to detecting, certain sudden pressure relays can trip the associated transformer circuitry in response to fault conditions, therefore limiting the potential damage on the equipment.[40]

There are three main types of fault pressure relays included within this general class of sudden pressure relays – rapid gas pressure rise devices, rapid oil pressure rise devices, and rapid oil flow devices. Rapid gas pressure relays monitor the pressure in the space above the oil (or other liquid) within the transformer, and initiate tripping action in response to a rapid rise in gas pressure resulting from the expansion of the liquid caused by a fault. Similarly, rapid oil pressure devices have a sensor located in the liquid and monitor the pressure in the oil (or other liquid), and initiate tripping action when a fault causes a rapid pressure rise. Finally, rapid oil flow devices monitor the liquid flow between a transformer/reactor and its conservator. Normal liquid flow occurs continuously with ambient temperature changes and with internal heating from loading and does not operate the rapid oil flow device. When an internal arc occurs, a sudden expansion of liquid can be monitored as rapid liquid flow from the transformer into the conservator, which triggers the fault pressure relay.[41]

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[40] NERC Petition, Ex. F, *Supplementary Reference and FAQ Document* at 12-14.

[41] *Id.*

Because certain applications of sudden pressure relays have the potential to impact the Bulk-Power System, it is beneficial to reliability that those relays be included within the scope of PRC-005. As described below, the three types of fault pressure relays described in this section are included within the definition of "Sudden Pressure Relaying" associated with the proposed PRC-005-4.

B. Modifications in proposed Reliability Standard PRC-005-4

As discussed below, certain parts of Reliability Standard PRC-005-3 have been modified in order to add the necessary Sudden Pressure Relaying to the PRC-005 Reliability Standard.

1. Definitions

NERC developed one new and four revised definitions along with proposed PRC-005-4.[42] NERC proposes the following new definition to define the scope of what is included when "Sudden Pressure Relaying" is referenced within the proposed PRC-005-4 Reliability Standard:

> **Sudden Pressure Relaying –** A system that trips an interrupting device(s) to isolate the equipment it is monitoring and includes the following Components:
>
> - Fault pressure relay – a mechanical relay or device that detects rapid changes in gas pressure, oil pressure, or oil flow that are indicative of Faults within liquid-filled, wire-wound equipment
> - Control circuitry associated with a fault pressure relay

This definition is intended only for use within the proposed Reliability Standard and will not, at this time, be listed in the NERC Glossary of Terms.[43] The term will be included within

[42] The definitions were posted in the draft PRC-005-4 Reliability Standard during the standards development process and will be implemented concurrently with the proposed Reliability Standard.

[43] NERC acknowledges the Commission's statement in Order No. 793 that "NERC should not adopt inconsistent definitions for the same term." *Protection System Maintenance Reliability Standard,* Order No. 793, 145 FERC ¶ 61,253 at P 70 (2013). Although this term will be posted along with the proposed Reliability Standard, NERC will not develop additional definitions of the same term approved for use in a particular Reliability Standard. If a future standards development project seeks to broaden the applicability of a standard-specific defined term, the

the posted Reliability Standard itself.[44] This definition reflects the SPCS Report recommendation and establishes that "Sudden Pressure Relaying" includes fault pressure relays and the associated control circuitry. The SPCS Report recommendation included both Component Types because a failure in either the fault pressure relay or the control circuitry may lead to an adverse reliability impact. For example, the control circuitry associated with a sudden pressure relay is the circuit which trips the breaker or other interrupting device. As noted above, the three main types of fault pressure relays – rapid gas pressure rise devices, rapid oil pressure rise devices, and rapid oil flow devices, are included within the scope of the definition of the proposed Reliability Standard.

In addition, the previously-approved defined terms "Protection System Maintenance Program", "Component Type", "Component", and "Countable Event." were revised to add the necessary reference to "Sudden Pressure Relaying" or the associated Table within the proposed Reliability Standard to facilitate coverage of Sudden Pressure Relaying Components within the PRC-005 Requirements. The revised definitions are as follows:

> **Protection System Maintenance Program (PSMP)** — An ongoing program by which Protection System, Automatic Reclosing, and Sudden Pressure Relaying Components are kept in working order and proper operation of malfunctioning Components is restored. A maintenance program for a specific Component includes one or more of the following activities:
>
> - Verify — Determine that the Component is functioning correctly.
> - Monitor — Observe the routine in-service operation of the Component.
> - Test — Apply signals to a Component to observe functional performance or output behavior, or to diagnose problems.

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defined term and where the term is posted (in the Reliability Standard or in the NERC Glossary of Terms) would need to be revisited through the standards development process.

44 For clarity, NERC relocated the definitions specific to the PRC-005 Reliability Standard into a separate section.in the posted version of the proposed Reliability Standard.

- Inspect — Examine for signs of Component failure, reduced performance or degradation.
- Calibrate — Adjust the operating threshold or measurement accuracy of a measuring element to meet the intended performance requirement.

Component Type –

- Any one of the five specific elements of a Protection System.
- Any one of the two specific elements of Automatic Reclosing.
- Any one of the two specific elements of Sudden Pressure Relaying.

Component –Any individual discrete piece of equipment included in a Protection System, Automatic Reclosing, or Sudden Pressure Relaying.

Countable Event – A failure of a Component requiring repair or replacement, any condition discovered during the maintenance activities in Tables 1-1 through 1-5, Table 3, Tables 4-1 through 4-2, and Table 5, which requires corrective action or a Protection System Misoperation attributed to hardware failure or calibration failure. Misoperations due to product design errors, software errors, relay settings different from specified settings, Protection System Component, Automatic Reclosing, or Sudden Pressure Relaying configuration or application errors are not included in Countable Events.

2. Applicability

a) Changes for Sudden Pressure Relaying

The specific locations for applicable Sudden Pressure Relaying are addressed in subsections 4.2.1, 4.2.5.2, 4.2.5.3, and 4.2.5.4, under the listing of covered "Facilities." The PRC-005-4 *Supplementary Reference and FAQ* document depicts which Sudden Pressure Relaying applications are included in the scope of the proposed PRC-005-4 Reliability Standard. The Applicability, as detailed below, was recommended by the SPCS Report after a review of the use of a wide range of devices that respond to non-electrical quantities. SPCS concluded that the only applicable non-electrical sensing devices are sudden pressure relays utilized in a trip application.[45]

> 4.2.1 Protection Systems and Sudden Pressure Relaying that are installed for the purpose of detecting Faults on BES Elements (lines, buses, transformers, etc.)
>
> ****
>
> 4.2.5 Protection Systems and Sudden Pressure Relaying for generator Facilities that are part of the BES, including:
>
> ****
>
>> 4.2.5.2 Protection Systems and Sudden Pressure Relaying for generator step-up transformers for generators that are part of the BES.
>>
>> 4.2.5.3 Protection Systems and Sudden Pressure Relaying for transformers connecting aggregated generation, where the aggregated generation is part of the BES (e.g., transformers connecting facilities such as wind-farms to the BES).
>>
>> 4.2.5.4 Protection Systems and Sudden Pressure Relaying for station service or excitation transformers connected to the generator bus of generators which are part of the BES, that act to trip the generator either directly or via lockout or tripping auxiliary relays.

The SPCS Report assessed Sudden Pressure Relaying for potential effects to Reliable Operation of the Bulk-Power System. The SPCS Report identified that non-electrical sensing devices that are utilized in a trip application can affect the reliability of the Bulk-Power System. The report concluded that these devices can quickly detect faults that could remain undetected by other Protection Systems and can trigger tripping of the equipment to limit potential damages.

45 *See* Exhibit F, *Supplementary Reference and FAQ*, at 12.

Therefore, certain applications of Sudden Pressure Relaying are addressed in PRC-005-4 by explicitly including fault pressure relays and their associated circuitry in the list of applicable Facilities, in addition to the Protection Systems that are already fall within the scope of the standard. Subsection 4.2.1 includes Sudden Pressure Relaying devices that are installed for the purpose of detecting Faults on Bulk-Electric System Elements. In addition, subsection 4.2.5 specifies that only Sudden Pressure Relaying for generator Facilities that are part of the Bulk-Electric System are included within the scope of the standard, and provides examples of such Facilities in subsections 4.2.5.2, 4.2.5.3, and 4.2.5.4.

In this context, the applicability of the proposed standard includes Sudden Pressure Relaying that detect faults on Bulk- Electric System Elements, and initiate tripping action to protect these Elements. The applicability extends only to Sudden Pressure Relaying that trips an interrupting device to isolate the equipment it is monitoring and protecting, and does not include other non-electrical sensing devices, pressure relays that only initiate an alarm, or pressure relief devices.[46]

b) Other Applicability Changes

In addition to the changes to the Applicability for the addition of Sudden Pressure Relaying, the term "Special Protection Systems" in subsection 4.2.4 and 4.2.6.3 were replaced by the term "Remedial Action Schemes."[47] These terms are currently synonymous in the NERC Glossary of Terms. This change is intended to align the proposed Reliability Standard with Project 2010-05.2 Phase 2 of Special Protection Systems where the standard drafting team has modified the definition of "Remedial Action Scheme" and begun the process of moving to

[46] *Id.* at 13.
[47] Exhibit A at 35.

employ the single term 'Remedial Action Scheme" in Reliability Standards in order to promote consistency.

Related to changes made in proposed PRC-005-3, the standard drafting team also revised section 4.2.6.1 and footnote 2 of the Applicability to address situations where Balancing Authorities participate in a Reserve Sharing Group.[48] The subsection now reads:

> Automatic Reclosing applied on the terminals of Elements connected to the BES bus located at generating plant substations where the total installed gross generating plant capacity is greater than the gross capacity of the largest BES generating unit within the Balancing Authority Area or, if a member of a Reserve Sharing Group, the largest generating unit within the Reserve Sharing Group.

In these cases, a group of Balancing Authorities share reserves to cover any contingency within the boundaries of the group; therefore, generation loss within a Reserve Sharing Group would not impact reliability of the Bulk-Power System unless the aggregate capacity loss exceeds the largest generating unit within the Reserve Sharing Group. This change is consistent with the rationale described in the SPCS Report for basing applicability on the "largest unit in the Balancing Authority Area."

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48 "Reserve Sharing Group" is defined in the NERC Glossary of Terms as

> A group whose members consist of two or more Balancing Authorities that collectively maintain, allocate, and supply operating reserves required for each Balancing Authority's use in recovering from contingencies within the group. Scheduling energy from an Adjacent Balancing Authority to aid recovery need not constitute reserve sharing provided the transaction is ramped in over a period the supplying party could reasonably be expected to load generation in (e.g., ten minutes). If the transaction is ramped in quicker (e.g., between zero and ten minutes) then, for the purposes of Disturbance Control Performance, the Areas become a Reserve Sharing Group.

NERC Glossary of Terms at 74.

3. Requirements in Reliability Standard PRC-005-4

The proposed Reliability Standard consists of five Requirements. The Requirements and the associated Measures have been modified, as necessary, to add in the coverage of Sudden Pressure Relaying to the proposed Requirement language. As a result of the addition, Proposed Requirement R1 requires that Transmission Owners, Generator Owners, and Distribution Providers also establish a Protection System Maintenance Program for Sudden Pressure Relaying. Proposed Requirement R3 now requires Transmission Owners, Generator Owners, and Distribution Providers that utilize time-based maintenance programs to maintain Sudden Pressure Relaying. Proposed Requirement R4 now requires Transmission Owners, Generator Owners, and Distribution Providers that utilize performance-based maintenance programs to implement and follow a Protection System Maintenance Program for Protection Systems, Automatic Reclosing, and Sudden Pressure Relaying. Revisions to Requirements R2 and R5 were not necessary as each will apply in the same fashion in the proposed Reliability Standard PRC-005-4.

The proposed Reliability Standard also includes proposed Table 5, which describes the maintenance activities and intervals for Sudden Pressure Relaying. Once the SPCS identified the devices for inclusion in the proposed Reliability Standard, it conducted an informal industry survey to develop recommendations for minimum maintenance activities and maximum maintenance intervals.[49] The SPCS survey received responses from seventy-five (75) Transmission Owners and one hundred nine (109) Generator Owners. Based on the survey, SPCS determined that the activities necessary for sudden pressure relay maintenance and testing are analogous to activities already performed during maintenance and testing of

[49] *Id* at 10.

electromechanical protective relays.[50] The SPCS also determined that the maximum interval for time-based maintenance programs should be six years.[51]

To validate the information collected from the survey, the SPCS performed an additional step in the analysis and contacted the following entities for their feedback: the IEEE Power System Relaying Committee, the IEEE Transformer Committee, the Doble Transformer Committee, the North American Transmission Form System Protection Practices Group, and the Electric Power Research Institute Generator Owner/Operator Technical Focus Group. All of these industry organizations indicated the results of the SPCS survey are consistent with their respective experiences.[52]

C. Implementation Plan

The Implementation Plan for proposed Reliability Standard PRC-005-4 addresses Protection Systems, Automatic Reclosing, and Sudden Pressure Relaying. PRC-005-2 has been approved by the Commission and has a twelve-year phased-in implementation period. The compliance dates for the various Requirements with respect to maintenance of Protection System and Automatic Reclosing Components in PRC-005-2 and PRC-005-3, respectively, key off of the date of approval of that specific version by an applicable regulatory authority. To account for this timing, and in order not to lose time on maintenance activities completed prior to the approval of PRC-005-4, the standard drafting team has carried forward the language in the approved implementation plan for PRC-005-2 and proposed implementation plan for PRC-005-

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[50] The maintenance of electromechanical protective relays is identified in Table 1-1: Protective Relay of PRC-005.

[51] *See* Table 1-1 of PRC-005-4, Exhibit A, p. 17. Table 5 of the proposed PRC-005-4 includes maintenance activities and intervals for Sudden Pressure Relaying. *See* Exhibit A at p. 37.

[52] *Id*. at p. 10.

3, and modified the language to add compliance dates for the Requirements with respect to Sudden Pressure Relaying.

Because PRC-005-4 has carried the Requirements from PRC-005-2 forward, including language regarding implementation timing, there is no need for an entity to cite to the prior versions of the Reliability Standard during the phased-in implementation period once the proposed Reliability Standard is approved.[53] Additional aspects of the Implementation Plan are addressed below.

1. Retirement of Legacy Reliability Standards

The Implementation Plan continues to reflect that the retirement of the legacy Reliability Standards will continue to key off of the applicable regulatory approval date of PRC-005-2. Because Sudden Pressure Relaying is a new Component covered by the PRC-005 Reliability Standard, the retirement of the legacy Reliability Standards does not need to correspond with the enforcement date of proposed PRC-005-4. Proposed PRC-005-4 will retire Reliability Standard PRC-005-3 "at midnight of the day immediately prior to the first day of the first calendar quarter following applicable regulatory approval of PRC-005-4."

2. Compliance Timeframes for Each Requirement

The Implementation Plan includes identical timeframes for entities to become compliant with the Requirements in PRC-005-4 as exist in the implementation plan for PRC-005-3. Entities will continue to calculate compliance dates for Requirements in connection with any Sudden Pressure Relaying by counting forward from the applicable regulatory approval date of PRC-005-4.

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[53] The same approach will be used with respect to Sudden Pressure Relaying. This will allow for the full retirement of PRC-005-3 and its Implementation Plan, leaving only one version of a new PRC-005 as the enforceable Reliability Standard rather than needing to reference versions 2 through 4 for the next twelve years.

D. Evidence Retention Periods

In order to establish effective maintenance procedures to ensure Reliable Operation of the Bulk-Power System, the standard drafting team established evidence retention periods associated with the proposed PRC-005-4. The retention periods are shorter than the ones required by the preceding versions of this Reliability Standard and reflect the Commission's concern expressed in the NOPR related to PRC-005-3. In the NOPR, the Commission noted that the data retention requirement for PRC-005-2 and PRC-005-3 could extend to 24 years (two 12-year maintenance cycles) and exceeds the three-year period that is routinely allowed for regulations requiring record retention.[54] The Commission sought comment regarding the reasonableness of the data retention obligations established by PRC-005-2 and PRC-005-3.[55]

In response to the NOPR, NERC consulted with compliance staff and determined that there is not a substantial need to maintain records for two maintenance cycles. Through the standards development process, NERC made the appropriate changes to the required evidence retention periods. The compliance section of the proposed PRC-005-4 now requires Transmission Owners, Generator Owners, and Distribution Providers to keep documentation of the most recent performance of maintenance activity for the relevant Component in cases where the interval of the maintenance activity is longer than the audit cycle. In cases where the interval of the maintenance activity is shorter than the audit cycle, documentation of all performances of the maintenance activity for the Component since the previous scheduled audit date must be retained.[56]

E. Enforceability of Proposed Reliability Standard PRC-005-4

[54] PRC-005-3 NOPR at P 33.
[55] *Id.* at P 39.
[56] *See* Exhibit A, Compliance Section.

The proposed Reliability Standard includes corresponding changes, where necessary, to the VRFs and VSLs to align with the changes to the Requirements in proposed PRC-005-4. The VRFs and VSLs for the proposed Reliability Standard comport with NERC and Commission guidelines related to their assignment. A detailed review of the VRFs, the VSLs, and the analysis of how the VRFs and VSLs were determined using these guidelines is provided in Exhibit G.

Because the Requirements contained in proposed Reliability Standard PRC-005-4 track with those contained in the previous versions, the standard drafting team determined that no revisions were necessary to the VRFs for the proposed Reliability Standard.[57] NERC, therefore, requests that the Commission approve the VRFs as applied to the Sudden Pressure Relaying Components now included in the proposed Reliability Standard.

The VSLs in PRC-005-3 have been revised accordingly to add the additional Component into the levels of severity. The changes are consistent with the approach taken for the VSLs in Reliability Standard PRC-005-3. The VSLs provide guidance on the way that NERC will enforce the Requirements of the proposed Reliability Standard for each of the Component Types.

V. <u>CONCLUSION</u>

For the reasons set forth above, NERC respectfully requests that the Commission:

- approve the proposed Reliability Standard and other associated elements included in Exhibit A;
- the new and revised definitions, as noted herein;
- the VRFs and VSLs (Exhibits A and G);
- approve the Implementation Plan included in Exhibit B; and

[57] The VSL change associated with PRC-005-2, as directed by the Commission, were reflected in PRC-005-3, and are included in the proposed PRC-005-4.

- approve the retirement of Reliability Standard PRC-005-3, as proposed in the Implementation Plan.

Respectfully submitted,

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Date: December 18, 2014

Exhibit A

Proposed Reliability Standard PRC-005-4

A. Introduction

1. **Title:** **Protection System, Automatic Reclosing, and Sudden Pressure Relaying Maintenance**
2. **Number: PRC-005-4**
3. **Purpose:** To document and implement programs for the maintenance of all Protection Systems, Automatic Reclosing, and Sudden Pressure Relaying affecting the reliability of the Bulk Electric System (BES) so that they are kept in working order.
4. **Applicability:**

4.1. Functional Entities:

4.1.1 Transmission Owner

4.1.2 Generator Owner

4.1.3 Distribution Provider

4.2. Facilities:

4.2.1 Protection Systems and Sudden Pressure Relaying that are installed for the purpose of detecting Faults on BES Elements (lines, buses, transformers, etc.)

4.2.2 Protection Systems used for underfrequency load-shedding systems installed per ERO underfrequency load-shedding requirements.

4.2.3 Protection Systems used for undervoltage load-shedding systems installed to prevent system voltage collapse or voltage instability for BES reliability.

4.2.4 Protection Systems installed as a Remedial Action Scheme (RAS) for BES reliability.

4.2.5 Protection Systems and Sudden Pressure Relaying for generator Facilities that are part of the BES, including:

4.2.5.1 Protection Systems that act to trip the generator either directly or via lockout or auxiliary tripping relays.

4.2.5.2 Protection Systems and Sudden Pressure Relaying for generator step-up transformers for generators that are part of the BES.

4.2.5.3 Protection Systems and Sudden Pressure Relaying for transformers connecting aggregated generation, where the aggregated generation is part of the BES (e.g., transformers connecting facilities such as wind-farms to the BES).

4.2.5.4 Protection Systems and Sudden Pressure Relaying for station service or excitation transformers connected to the generator bus of generators which are part of the BES, that act to trip the generator either directly or via lockout or tripping auxiliary relays.

4.2.6 Automatic Reclosing[1], including:

4.2.6.1 Automatic Reclosing applied on the terminals of Elements connected to the BES bus located at generating plant substations where the total installed gross generating plant capacity is greater than the gross capacity of the largest BES generating unit within the Balancing Authority Area or, if a member of a Reserve Sharing Group, the largest generating unit within the Reserve Sharing Group.[2]

4.2.6.2 Automatic Reclosing applied on the terminals of all BES Elements at substations one bus away from generating plants specified in Section 4.2.6.1 when the substation is less than 10 circuit-miles from the generating plant substation.

4.2.6.3 Automatic Reclosing applied as an integral part of an RAS specified in Section 4.2.4.

5. **Effective Date:** See Implementation Plan

6. **Definitions Used in this Standard:**

Automatic Reclosing – Includes the following Components:

- Reclosing relay
- Control circuitry associated with the reclosing relay.

Sudden Pressure Relaying – A system that trips an interrupting device(s) to isolate the equipment it is monitoring and includes the following Components:

- Fault pressure relay – a mechanical relay or device that detects rapid changes in gas pressure, oil pressure, or oil flow that are indicative of Faults within liquid-filled, wire-wound equipment
- Control circuitry associated with a fault pressure relay

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[1] Automatic Reclosing addressed in Section 4.2.6.1 and 4.2.6.2 may be excluded if the equipment owner can demonstrate that a close-in three-phase fault present for twice the normal clearing time (capturing a minimum trip-close-trip time delay) does not result in a total loss of gross generation in the Interconnection exceeding the gross capacity of the largest relevant BES generating unit where the Automatic Reclosing is applied.

[2] The largest BES generating unit within the Balancing Authority Area or the largest generating unit within the Reserve Sharing Group, as applicable, is subject to change. As a result of such a change, the Automatic Reclosing Components subject to the standard could change effective on the date of such change.

Unresolved Maintenance Issue – A deficiency identified during a maintenance activity that causes the Component to not meet the intended performance, cannot be corrected during the maintenance interval, and requires follow-up corrective action.

Segment – Components of a consistent design standard, or a particular model or type from a single manufacturer that typically share other common elements. Consistent performance is expected across the entire population of a Segment. A Segment must contain at least sixty (60) individual Components.

Component Type –

- Any one of the five specific elements of a Protection System.
- Any one of the two specific elements of Automatic Reclosing.
- Any one of the two specific elements of Sudden Pressure Relaying.

Component – Any individual discrete piece of equipment included in a Protection System, Automatic Reclosing, or Sudden Pressure Relaying.

Countable Event – A failure of a Component requiring repair or replacement, any condition discovered during the maintenance activities in Tables 1-1 through 1-5, Table 3, Tables 4-1 through 4-2, and Table 5, which requires corrective action or a Protection System Misoperation attributed to hardware failure or calibration failure. Misoperations due to product design errors, software errors, relay settings different from specified settings, Protection System Component, Automatic Reclosing, or Sudden Pressure Relaying configuration or application errors are not included in Countable Events.

B. Requirements and Measures

R1. Each Transmission Owner, Generator Owner, and Distribution Provider shall establish a Protection System Maintenance Program (PSMP) for its Protection Systems, Automatic Reclosing, and Sudden Pressure Relaying identified in Section 4.2, Facilities. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning*]

The PSMP shall:

1.1. Identify which maintenance method (time-based, performance-based per PRC-005 Attachment A, or a combination) is used to address each Protection System, Automatic Reclosing, and Sudden Pressure Relaying Component Type. All batteries associated with the station dc supply Component Type of a Protection System shall be included in a time-based program as described in Table 1-4 and Table 3.

1.2. Include the applicable monitored Component attributes applied to each Protection System, Automatic Reclosing, and Sudden Pressure Relaying Component Type consistent with the maintenance intervals specified in Tables 1-

1 through 1-5, Table 2, Table 3, Table 4-1 through 4-2, and Table 5 where monitoring is used to extend the maintenance intervals beyond those specified for unmonitored Protection System, Automatic Reclosing, and Sudden Pressure Relaying Components.

M1. Each Transmission Owner, Generator Owner and Distribution Provider shall have a documented Protection System Maintenance Program in accordance with Requirement R1.

For each Protection System, Automatic Reclosing, and Sudden Pressure Relaying Component Type, the documentation shall include the type of maintenance method applied (time-based, performance-based, or a combination of these maintenance methods), and shall include all batteries associated with the station dc supply Component Types in a time-based program as described in Table 1-4 and Table 3. (Part 1.1)

For Component Types that use monitoring to extend the maintenance intervals, the responsible entity(s) shall have evidence for each Protection System, Automatic Reclosing, and Sudden Pressure Relaying Component Type (such as manufacturer's specifications or engineering drawings) of the appropriate monitored Component attributes as specified in Tables 1-1 through 1-5, Table 2, Table 3, Table 4-1 through 4-2, and Table 5. (Part 1.2)

R2. Each Transmission Owner, Generator Owner, and Distribution Provider that uses performance-based maintenance intervals in its PSMP shall follow the procedure established in PRC-005 Attachment A to establish and maintain its performance-based intervals. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

M2. Each Transmission Owner, Generator Owner, and Distribution Provider that uses performance-based maintenance intervals shall have evidence that its current performance-based maintenance program(s) is in accordance with Requirement R2, which may include, but is not limited to, Component lists, dated maintenance records, and dated analysis records and results.

R3. Each Transmission Owner, Generator Owner, and Distribution Provider that utilizes time-based maintenance program(s) shall maintain its Protection System, Automatic Reclosing, and Sudden Pressure Relaying Components that are included within the time-based maintenance program in accordance with the minimum maintenance activities and maximum maintenance intervals prescribed within Tables 1-1 through 1-5, Table 2, Table 3, Table 4-1 through 4-2, and Table 5. *[Violation Risk Factor: High] [Time Horizon: Operations Planning]*

M3. Each Transmission Owner, Generator Owner, and Distribution Provider that utilizes time-based maintenance program(s) shall have evidence that it has maintained its Protection System, Automatic Reclosing, and Sudden Pressure Relaying Components included within its time-based program in accordance with Requirement R3. The evidence may include, but is not limited to, dated maintenance records, dated maintenance summaries, dated check-off lists, dated inspection records, or dated work orders.

R4. Each Transmission Owner, Generator Owner, and Distribution Provider that utilizes performance-based maintenance program(s) in accordance with Requirement R2 shall implement and follow its PSMP for its Protection System, Automatic Reclosing, and Sudden Pressure Relaying Components that are included within the performance-based program(s). *[Violation Risk Factor: High] [Time Horizon: Operations Planning]*

M4. Each Transmission Owner, Generator Owner, and Distribution Provider that utilizes performance-based maintenance intervals in accordance with Requirement R2 shall have evidence that it has implemented the Protection System Maintenance Program for the Protection System, Automatic Reclosing, and Sudden Pressure Relaying Components included in its performance-based program in accordance with Requirement R4. The evidence may include, but is not limited to, dated maintenance records, dated maintenance summaries, dated check-off lists, dated inspection records, or dated work orders.

R5. Each Transmission Owner, Generator Owner, and Distribution Provider shall demonstrate efforts to correct identified Unresolved Maintenance Issues. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

M5. Each Transmission Owner, Generator Owner, and Distribution Provider shall have evidence that it has undertaken efforts to correct identified Unresolved Maintenance Issues in accordance with Requirement R5. The evidence may include, but is not limited to, work orders, replacement Component orders, invoices, project schedules with completed milestones, return material authorizations (RMAs) or purchase orders.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

As defined in the NERC Rules of Procedure, “Compliance Enforcement Authority” means NERC or the Regional Entity in their respective roles of monitoring and enforcing compliance with the NERC Reliability Standards.

1.2. Evidence Retention

The following evidence retention periods identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

The Transmission Owner, Generator Owner, and Distribution Provider shall each keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

For Requirement R1, the Transmission Owner, Generator Owner, and Distribution Provider shall each keep its current dated Protection System Maintenance Program, as well as any superseded versions since the preceding compliance audit, including the documentation that specifies the type of maintenance program applied for each Protection System, Automatic Reclosing, or Sudden Pressure Relaying Component Type.

For Requirement R2, Requirement R3, and Requirement R4, in cases where the interval of the maintenance activity is longer than the audit cycle, the Transmission Owner, Generator Owner, and Distribution Provider shall each keep documentation of the most recent performance of that maintenance activity for the Protection System, Automatic Reclosing, or Sudden Pressure Relaying Component. In cases where the interval of the maintenance activity is shorter than the audit cycle, documentation of all performances (in accordance with the tables) of that maintenance activity for the Protection System, Automatic Reclosing, or Sudden Pressure Relaying Component since the previous scheduled audit date shall be retained.

For Requirement R5 the Transmission Owner, Generator Owner, and Distribution Provider shall each keep documentation of Unresolved Maintenance Issues identified by the entity since the last audit, including all that were resolved since the last audit.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.3. Compliance Monitoring and Assessment Processes:

Compliance Audits

Self-Certifications

Spot Checking

Compliance Violation Investigations

Self-Reporting

Complaints

1.4. Additional Compliance Information

None

Table of Compliance Elements

Requirement Number	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	The entity's PSMP failed to specify whether one Component Type is being addressed by time-based or performance-based maintenance, or a combination of both (Part 1.1).	The entity's PSMP failed to specify whether two Component Types are being addressed by time-based or performance-based maintenance, or a combination of both (Part 1.1).	The entity's PSMP failed to specify whether three Component Types are being addressed by time-based or performance-based maintenance, or a combination of both. (Part 1.1). OR The entity's PSMP failed to include the applicable monitoring attributes applied to each Component Type consistent with the maintenance intervals specified in Tables 1-1 through 1-5, Table 2, Table 3, Tables 4-1 through 4-2, and Table 5 where monitoring is used to extend the maintenance intervals beyond those specified for unmonitored Components (Part 1.2).	The entity failed to establish a PSMP. OR The entity's PSMP failed to specify whether four or more Component Types are being addressed by time-based or performance-based maintenance, or a combination of both (Part 1.1). OR The entity's PSMP failed to include applicable station batteries in a time-based program (Part 1.1).
R2	The entity uses performance-based maintenance intervals in its PSMP but failed to reduce Countable Events to no more than 4% within three years.	NA	The entity uses performance-based maintenance intervals in its PSMP but failed to reduce Countable Events to no more than 4% within four years.	The entity uses performance-based maintenance intervals in its PSMP but: 1) Failed to establish the technical justification described within Requirement R2 for the initial use of the performance-based PSMP OR 2) Failed to reduce Countable Events to no more than 4% within five years OR

Requirement Number	Lower VSL	Moderate VSL	High VSL	Severe VSL
				3) Maintained a Segment with less than 60 Components OR 4) Failed to: • Annually update the list of Components, OR • Annually perform maintenance on the greater of 5% of the Segment population or 3 Components, OR • Annually analyze the program activities and results for each Segment.
R3	For Components included within a time-based maintenance program, the entity failed to maintain 5% or less of the total Components included within a specific Component Type in accordance with the minimum maintenance activities and maximum maintenance intervals prescribed within Tables 1-1 through 1-5, Table 2, Table 3, Tables 4-1 through 4-2, and Table 5.	For Components included within a time-based maintenance program, the entity failed to maintain more than 5% but 10% or less of the total Components included within a specific Component Type in accordance with the minimum maintenance activities and maximum maintenance intervals prescribed within Tables 1-1 through 1-5, Table 2, Table 3, Tables 4-1 through 4-2, and Table 5.	For Components included within a time-based maintenance program, the entity failed to maintain more than 10% but 15% or less of the total Components included within a specific Component Type in accordance with the minimum maintenance activities and maximum maintenance intervals prescribed within Tables 1-1 through 1-5, Table 2, Table 3, Tables 4-1 through 4-2, and Table 5.	For Components included within a time-based maintenance program, the entity failed to maintain more than 15% of the total Components included within a specific Component Type in accordance with the minimum maintenance activities and maximum maintenance intervals prescribed within Tables 1-1 through 1-5, Table 2, Table 3, Tables 4-1 through 4-2, and Table 5.

Requirement Number	Lower VSL	Moderate VSL	High VSL	Severe VSL
R4	For Components included within a performance-based maintenance program, the entity failed to maintain 5% or less of the annual scheduled maintenance for a specific Component Type in accordance with their performance-based PSMP.	For Components included within a performance-based maintenance program, the entity failed to maintain more than 5% but 10% or less of the annual scheduled maintenance for a specific Component Type in accordance with their performance-based PSMP.	For Components included within a performance-based maintenance program, the entity failed to maintain more than 10% but 15% or less of the annual scheduled maintenance for a specific Component Type in accordance with their performance-based PSMP.	For Components included within a performance-based maintenance program, the entity failed to maintain more than 15% of the annual scheduled maintenance for a specific Component Type in accordance with their performance-based PSMP.
R5	The entity failed to undertake efforts to correct 5 or fewer identified Unresolved Maintenance Issues.	The entity failed to undertake efforts to correct greater than 5 but less than or equal to 10 identified Unresolved Maintenance Issues.	The entity failed to undertake efforts to correct greater than 10 but less than or equal to 15 identified Unresolved Maintenance Issues.	The entity failed to undertake efforts to correct greater than 15 identified Unresolved Maintenance Issues.

D. Regional Variances

None.

E. Interpretations

None.

Supplemental Reference Documents

The following documents present a detailed discussion about determination of maintenance intervals and other useful information regarding establishment of a maintenance program.

1. *Supplementary Reference and FAQ - PRC-005-4 Protection System Maintenance,* Protection System Maintenance and Testing Standard Drafting Team (April 2014)
2. *Considerations for Maintenance and Testing of Auto-reclosing Schemes*, NERC System Analysis and Modeling Subcommittee, and NERC System Protection and Control Subcommittee (November 2012)
3. *Sudden Pressure Relays and Other Devices that Respond to Non-Electrical Quantities – SPCS Input for Standard Development in Response to FERC Order No. 758,* NERC System Protection and Control Subcommittee (December 2013)
4. *Sudden Pressure Relays and Other Devices that Respond to Non-Electrical Quantities –* Supplemental Information to Support Project 2007-17.3: Protection System Maintenance and Testing (October 31, 2014)

Version History

Version	Date	Action	Change Tracking
0	February 8, 2005	Adopted by NERC Board of Trustees	New
1	February 7, 2006	Adopted by NERC Board of Trustees	1. Changed incorrect use of certain hyphens (-) to “en dash” (–) and “em dash (—).” 2. Added “periods” to items where appropriate. Changed “Timeframe” to “Time Frame” in item D, 1.2.
1a	February 17, 2011	Adopted by NERC Board of Trustees	Added Appendix 1 - Interpretation regarding applicability of standard to protection of radially connected transformers developed in Project 2009-17

Version	Date	Action	Change Tracking
1b	November 5, 2009	Adopted by NERC Board of Trustees	Interpretation of R1, R1.1, and R1.2 developed by Project 2009-10
1b	February 3, 2012	FERC Order approving revised definition of "Protection System"	Per footnote 8 of FERC's order, the definition of "Protection System" supersedes interpretation "b" of PRC-005-1b upon the effective date of the modified definition (i.e., April 1, 2013) *See N. Amer. Elec. Reliability Corp.*, 138 FERC ¶ 61,095 (February 3, 2012).
1.1b	May 9, 2012	Adopted by NERC Board of Trustees	Errata change developed by Project 2010-07, clarified inclusion of generator interconnection Facility in Generator Owner's responsibility
2	November 7, 2012	Adopted by NERC Board of Trustees	Project 2007-17 - Complete revision, absorbing maintenance requirements from PRC-005-1.1b, PRC-008-0, PRC-011-0, PRC-017-0
2	October 17, 2013	Approved by NERC Standards Committee	Errata Change: The Standards Committee approved an errata change to the implementation plan for PRC-005-2 to add the phrase "or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities;" to the second sentence under the "Retirement of Existing Standards" section. (no change to standard version number)
2	March 7, 2014	Adopted by NERC Board of Trustees	Modified R1 VSL in response to FERC directive (no change to standard version number)
2(i)	November 13, 2014	Adopted by NERC Board of Trustees	Applicability section revised by Project 2014-01 to clarify application of Requirements to BES dispersed power producing resources

Version	Date	Action	Change Tracking
2(ii)	November 13, 2014	Adopted by NERC Board of Trustees	Replaced references to Special Protection System and SPS with Remedial Action Scheme and RAS
3	November 7, 2013	Adopted by the NERC Board of Trustees	Revised to address the FERC directive in Order No. 758 to include Automatic Reclosing in maintenance programs
3	February 12, 2014	Approved by NERC Standards Committee	Errata Change: The Standards Committee approved errata changes to correct capitalization of certain defined terms within the definitions of "Unresolved Maintenance Issue" and "Protection System Maintenance Program". The changes will be reflected in the definitions section of PRC-005-3 for "Unresolved Maintenance Issue" and in the NERC Glossary of Terms for "Protection System Maintenance Program". (no change to standard version number)
3	March 7, 2014	Adopted by NERC Board of Trustees	Modified R1 VSL in response to FERC directive (no change to standard version number)
3(i)	November 13, 2014	Adopted by NERC Board of Trustees	Applicability section revised by Project 2014-01 to clarify application of Requirements to BES dispersed power producing resources
3(ii)	November 13, 2014	Adopted by NERC Board of Trustees	Replaced references to Special Protection System and SPS with Remedial Action Scheme and RAS
4	November 13, 2014	Adopted by NERC Board of Trustees	Added Sudden Pressure Relaying in response to FERC Order No. 758

Table 1-1 Component Type - Protective Relay Excluding distributed UFLS and distributed UVLS (see Table 3)		
Component Attributes	**Maximum Maintenance Interval[3]**	**Maintenance Activities**
Any unmonitored protective relay not having all the monitoring attributes of a category below.	6 Calendar Years	For all unmonitored relays: • Verify that settings are as specified For non-microprocessor relays: • Test and, if necessary calibrate For microprocessor relays: • Verify operation of the relay inputs and outputs that are essential to proper functioning of the Protection System. • Verify acceptable measurement of power system input values.
Monitored microprocessor protective relay with the following: • Internal self-diagnosis and alarming (see Table 2). • Voltage and/or current waveform sampling three or more times per power cycle, and conversion of samples to numeric values for measurement calculations by microprocessor electronics. • Alarming for power supply failure (see Table 2).	12 Calendar Years	Verify: • Settings are as specified. • Operation of the relay inputs and outputs that are essential to proper functioning of the Protection System. • Acceptable measurement of power system input values.

[3] For the tables in this standard, a calendar year starts on the first day of a new year (January 1) after a maintenance activity has been completed.
For the tables in this standard, a calendar month starts on the first day of the first month after a maintenance activity has been completed.

Table 1-1 Component Type - Protective Relay Excluding distributed UFLS and distributed UVLS (see Table 3)		
Component Attributes	**Maximum Maintenance Interval**[3]	**Maintenance Activities**
Monitored microprocessor protective relay with preceding row attributes and the following: • Ac measurements are continuously verified by comparison to an independent ac measurement source, with alarming for excessive error (See Table 2). • Some or all binary or status inputs and control outputs are monitored by a process that continuously demonstrates ability to perform as designed, with alarming for failure (See Table 2). • Alarming for change of settings (See Table 2).	12 Calendar Years	Verify only the unmonitored relay inputs and outputs that are essential to proper functioning of the Protection System.

Table 1-2 Component Type - Communications Systems Excluding distributed UFLS and distributed UVLS (see Table 3)		
Component Attributes	**Maximum Maintenance Interval**	**Maintenance Activities**
Any unmonitored communications system necessary for correct operation of protective functions, and not having all the monitoring attributes of a category below.	4 Calendar Months	Verify that the communications system is functional.
	6 Calendar Years	Verify that the communications system meets performance criteria pertinent to the communications technology applied (e.g. signal level, reflected power, or data error rate). Verify operation of communications system inputs and outputs that are essential to proper functioning of the Protection System.
Any communications system with continuous monitoring or periodic automated testing for the presence of the channel function, and alarming for loss of function (See Table 2).	12 Calendar Years	Verify that the communications system meets performance criteria pertinent to the communications technology applied (e.g. signal level, reflected power, or data error rate). Verify operation of communications system inputs and outputs that are essential to proper functioning of the Protection System.
Any communications system with all of the following: • Continuous monitoring or periodic automated testing for the performance of the channel using criteria pertinent to the communications technology applied (e.g. signal level, reflected power, or data error rate, and alarming for excessive performance degradation). (See Table 2) • Some or all binary or status inputs and control outputs are monitored by a process that continuously demonstrates ability to perform as designed, with alarming for failure (See Table 2).	12 Calendar Years	Verify only the unmonitored communications system inputs and outputs that are essential to proper functioning of the Protection System

Table 1-3 Component Type - Voltage and Current Sensing Devices Providing Inputs to Protective Relays Excluding distributed UFLS and distributed UVLS (see Table 3)		
Component Attributes	**Maximum Maintenance Interval**	**Maintenance Activities**
Any voltage and current sensing devices not having monitoring attributes of the category below.	12 Calendar Years	Verify that current and voltage signal values are provided to the protective relays.
Voltage and Current Sensing devices connected to microprocessor relays with AC measurements are continuously verified by comparison of sensing input value, as measured by the microprocessor relay, to an independent ac measurement source, with alarming for unacceptable error or failure (see Table 2).	No periodic maintenance specified	None.

Table 1-4(a) Component Type – Protection System Station dc Supply Using Vented Lead-Acid (VLA) Batteries Excluding distributed UFLS and distributed UVLS (see Table 3) Protection System Station dc supply used only for non-BES interrupting devices for RAS, non-distributed UFLS systems, or non-distributed UVLS systems is excluded (see Table 1-4(e)).		
Component Attributes	**Maximum Maintenance Interval**	**Maintenance Activities**
Protection System Station dc supply using Vented Lead-Acid (VLA) batteries not having monitoring attributes of Table 1-4(f).	4 Calendar Months	Verify: • Station dc supply voltage Inspect: • Electrolyte level • For unintentional grounds
	18 Calendar Months	Verify: • Float voltage of battery charger • Battery continuity • Battery terminal connection resistance • Battery intercell or unit-to-unit connection resistance Inspect: • Cell condition of all individual battery cells where cells are visible – or measure battery cell/unit internal ohmic values where the cells are not visible • Physical condition of battery rack

Table 1-4(a) Component Type – Protection System Station dc Supply Using Vented Lead-Acid (VLA) Batteries Excluding distributed UFLS and distributed UVLS (see Table 3) Protection System Station dc supply used only for non-BES interrupting devices for RAS, non-distributed UFLS systems, or non-distributed UVLS systems is excluded (see Table 1-4(e)).		
Component Attributes	**Maximum Maintenance Interval**	**Maintenance Activities**
	18 Calendar Months -or- 6 Calendar Years	Verify that the station battery can perform as manufactured by evaluating cell/unit measurements indicative of battery performance (e.g. internal ohmic values or float current) against the station battery baseline. -or- Verify that the station battery can perform as manufactured by conducting a performance or modified performance capacity test of the entire battery bank.

Table 1-4(b) Component Type – Protection System Station dc Supply Using Valve-Regulated Lead-Acid (VRLA) Batteries Excluding distributed UFLS and distributed UVLS (see Table 3) Protection System Station dc supply used only for non-BES interrupting devices for RAS, non-distributed UFLS systems, or non-distributed UVLS systems is excluded (see Table 1-4(e)).		
Component Attributes	**Maximum Maintenance Interval**	**Maintenance Activities**
Protection System Station dc supply with Valve Regulated Lead-Acid (VRLA) batteries not having monitoring attributes of Table 1-4(f).	4 Calendar Months	Verify: • Station dc supply voltage Inspect: • For unintentional grounds
	6 Calendar Months	Inspect: • Condition of all individual units by measuring battery cell/unit internal ohmic values.
	18 Calendar Months	Verify: • Float voltage of battery charger • Battery continuity • Battery terminal connection resistance • Battery intercell or unit-to-unit connection resistance Inspect: • Physical condition of battery rack

Table 1-4(b) Component Type – Protection System Station dc Supply Using Valve-Regulated Lead-Acid (VRLA) Batteries Excluding distributed UFLS and distributed UVLS (see Table 3) Protection System Station dc supply used only for non-BES interrupting devices for RAS, non-distributed UFLS systems, or non-distributed UVLS systems is excluded (see Table 1-4(e)).		
Component Attributes	**Maximum Maintenance Interval**	**Maintenance Activities**
	6 Calendar Months -or- 3 Calendar Years	Verify that the station battery can perform as manufactured by evaluating cell/unit measurements indicative of battery performance (e.g. internal ohmic values or float current) against the station battery baseline. -or- Verify that the station battery can perform as manufactured by conducting a performance or modified performance capacity test of the entire battery bank.

Table 1-4(c) **Component Type – Protection System Station dc Supply Using Nickel-Cadmium (NiCad) Batteries** **Excluding distributed UFLS and distributed UVLS (see Table 3)** **Protection System Station dc supply used only for non-BES interrupting devices for RAS, non-distributed UFLS system, or non-distributed UVLS systems is excluded (see Table 1-4(e)).**		
Component Attributes	**Maximum Maintenance Interval**	**Maintenance Activities**
Protection System Station dc supply **Nickel-Cadmium (NiCad) batteries** not having monitoring attributes of Table 1-4(f).	4 Calendar Months	Verify: • Station dc supply voltage Inspect: • Electrolyte level • For unintentional grounds
	18 Calendar Months	Verify: • Float voltage of battery charger • Battery continuity • Battery terminal connection resistance • Battery intercell or unit-to-unit connection resistance Inspect: • Cell condition of all individual battery cells. • Physical condition of battery rack

Table 1-4(c) Component Type – Protection System Station dc Supply Using Nickel-Cadmium (NiCad) Batteries Excluding distributed UFLS and distributed UVLS (see Table 3) Protection System Station dc supply used only for non-BES interrupting devices for RAS, non-distributed UFLS system, or non-distributed UVLS systems is excluded (see Table 1-4(e)).		
Component Attributes	**Maximum Maintenance Interval**	**Maintenance Activities**
	6 Calendar Years	Verify that the station battery can perform as manufactured by conducting a performance or modified performance capacity test of the entire battery bank.

Table 1-4(d) **Component Type – Protection System Station dc Supply Using Non Battery Based Energy Storage** **Excluding distributed UFLS and distributed UVLS (see Table 3)** **Protection System Station dc supply used only for non-BES interrupting devices for RAS, non-distributed UFLS system, or non-distributed UVLS systems is excluded (see Table 1-4(e)).**		
Component Attributes	**Maximum Maintenance Interval**	**Maintenance Activities**
Any Protection System station dc supply not using a battery and not having monitoring attributes of Table 1-4(f).	4 Calendar Months	Verify: • Station dc supply voltage Inspect: • For unintentional grounds
	18 Calendar Months	Inspect: Condition of non-battery based dc supply
	6 Calendar Years	Verify that the dc supply can perform as manufactured when ac power is not present.

Table 1-4(e) Component Type – Protection System Station dc Supply for non-BES Interrupting Devices for RAS, non-distributed UFLS, and non-distributed UVLS systems		
Component Attributes	**Maximum Maintenance Interval**	**Maintenance Activities**
Any Protection System dc supply used for tripping only non-BES interrupting devices as part of a RAS, non-distributed UFLS, or non-distributed UVLS system and not having monitoring attributes of Table 1-4(f).	When control circuits are verified (See Table 1-5)	Verify Station dc supply voltage.

Table 1-4(f) Exclusions for Protection System Station dc Supply Monitoring Devices and Systems		
Component Attributes	**Maximum Maintenance Interval**	**Maintenance Activities**
Any station dc supply with high and low voltage monitoring and alarming of the battery charger voltage to detect charger overvoltage and charger failure (See Table 2).	No periodic maintenance specified	No periodic verification of station dc supply voltage is required.
Any battery based station dc supply with electrolyte level monitoring and alarming in every cell (See Table 2).		No periodic inspection of the electrolyte level for each cell is required.
Any station dc supply with unintentional dc ground monitoring and alarming (See Table 2).		No periodic inspection of unintentional dc grounds is required.
Any station dc supply with charger float voltage monitoring and alarming to ensure correct float voltage is being applied on the station dc supply (See Table 2).		No periodic verification of float voltage of battery charger is required.
Any battery based station dc supply with monitoring and alarming of battery string continuity (See Table 2).		No periodic verification of the battery continuity is required.
Any battery based station dc supply with monitoring and alarming of the intercell and/or terminal connection detail resistance of the entire battery (See Table 2).		No periodic verification of the intercell and terminal connection resistance is required.
Any Valve Regulated Lead-Acid (VRLA) or Vented Lead-Acid (VLA) station battery with internal ohmic value or float current monitoring and alarming, and evaluating present values relative to baseline internal ohmic values for every cell/unit (See Table 2).		No periodic evaluation relative to baseline of battery cell/unit measurements indicative of battery performance is required to verify the station battery can perform as manufactured.
Any Valve Regulated Lead-Acid (VRLA) or Vented Lead-Acid (VLA) station battery with monitoring and alarming of each cell/unit internal ohmic value (See Table 2).		No periodic inspection of the condition of all individual units by measuring battery cell/unit internal ohmic values of a station VRLA or Vented Lead-Acid (VLA) battery is required.

Table 1-5 Component Type - Control Circuitry Associated With Protective Functions Excluding distributed UFLS and distributed UVLS (see Table 3), Automatic Reclosing (see Table 4), and Sudden Pressure Relaying (see Table 5) Note: Table requirements apply to all Control Circuitry Components of Protection Systems, and RAS except as noted.		
Component Attributes	**Maximum Maintenance Interval**	**Maintenance Activities**
Trip coils or actuators of circuit breakers, interrupting devices, or mitigating devices (regardless of any monitoring of the control circuitry).	6 Calendar Years	Verify that each trip coil is able to operate the circuit breaker, interrupting device, or mitigating device.
Electromechanical lockout devices which are directly in a trip path from the protective relay to the interrupting device trip coil (regardless of any monitoring of the control circuitry).	6 Calendar Years	Verify electrical operation of electromechanical lockout devices.
Unmonitored control circuitry associated with RAS. (See Table 4-2(b) for RAS which include Automatic Reclosing.)	12 Calendar Years	Verify all paths of the control circuits essential for proper operation of the RAS.
Unmonitored control circuitry associated with protective functions inclusive of all auxiliary relays.	12 Calendar Years	Verify all paths of the trip circuits inclusive of all auxiliary relays through the trip coil(s) of the circuit breakers or other interrupting devices.
Control circuitry associated with protective functions and/or RAS whose integrity is monitored and alarmed (See Table 2).	No periodic maintenance specified	None.

Table 2 – Alarming Paths and Monitoring In Tables 1-1 through 1-5, Table 3, Tables 4-1 through 4-2, and Table 5 alarm attributes used to justify extended maximum maintenance intervals and/or reduced maintenance activities are subject to the following maintenance requirements		
Component Attributes	**Maximum Maintenance Interval**	**Maintenance Activities**
Any alarm path through which alarms in Tables 1-1 through 1-5, Table 3, Tables 4-1 through 4-2, and Table 5 are conveyed from the alarm origin to the location where corrective action can be initiated, and not having all the attributes of the "Alarm Path with monitoring" category below. Alarms are reported within 24 hours of detection to a location where corrective action can be initiated.	12 Calendar Years	Verify that the alarm path conveys alarm signals to a location where corrective action can be initiated.
Alarm Path with monitoring: The location where corrective action is taken receives an alarm within 24 hours for failure of any portion of the alarming path from the alarm origin to the location where corrective action can be initiated.	No periodic maintenance specified	None.

Table 3 Maintenance Activities and Intervals for distributed UFLS and distributed UVLS Systems		
Component Attributes	**Maximum Maintenance Interval**	**Maintenance Activities**
Any unmonitored protective relay not having all the monitoring attributes of a category below.	6 Calendar Years	Verify that settings are as specified. For non-microprocessor relays: • Test and, if necessary calibrate. For microprocessor relays: • Verify operation of the relay inputs and outputs that are essential to proper functioning of the Protection System. • Verify acceptable measurement of power system input values.
Monitored microprocessor protective relay with the following: • Internal self-diagnosis and alarming (See Table 2). • Voltage and/or current waveform sampling three or more times per power cycle, and conversion of samples to numeric values for measurement calculations by microprocessor electronics. Alarming for power supply failure (See Table 2).	12 Calendar Years	Verify: • Settings are as specified. • Operation of the relay inputs and outputs that are essential to proper functioning of the Protection System. • Acceptable measurement of power system input values
Monitored microprocessor protective relay with preceding row attributes and the following: • Ac measurements are continuously verified by comparison to an independent ac measurement source, with alarming for excessive error (See Table 2).	12 Calendar Years	Verify only the unmonitored relay inputs and outputs that are essential to proper functioning of the Protection System.

Table 3 Maintenance Activities and Intervals for distributed UFLS and distributed UVLS Systems		
Component Attributes	**Maximum Maintenance Interval**	**Maintenance Activities**
• Some or all binary or status inputs and control outputs are monitored by a process that continuously demonstrates ability to perform as designed, with alarming for failure (See Table 2). Alarming for change of settings (See Table 2).		
Voltage and/or current sensing devices associated with UFLS or UVLS systems.	12 Calendar Years	Verify that current and/or voltage signal values are provided to the protective relays.
Protection System dc supply for tripping non-BES interrupting devices used only for a UFLS or UVLS system.	12 Calendar Years	Verify Protection System dc supply voltage.
Control circuitry between the UFLS or UVLS relays and electromechanical lockout and/or tripping auxiliary devices (excludes non-BES interrupting device trip coils).	12 Calendar Years	Verify the path from the relay to the lockout and/or tripping auxiliary relay (including essential supervisory logic).
Electromechanical lockout and/or tripping auxiliary devices associated only with UFLS or UVLS systems (excludes non-BES interrupting device trip coils).	12 Calendar Years	Verify electrical operation of electromechanical lockout and/or tripping auxiliary devices.
Control circuitry between the electromechanical lockout and/or tripping auxiliary devices and the non-BES interrupting devices in UFLS or UVLS systems, or between UFLS or UVLS relays (with no interposing electromechanical lockout or auxiliary device) and the non-BES interrupting devices (excludes non-BES interrupting device trip coils).	No periodic maintenance specified	None.
Trip coils of non-BES interrupting devices in UFLS or UVLS systems.	No periodic maintenance specified	None.

Table 4-1 Maintenance Activities and Intervals for Automatic Reclosing Components Component Type – Reclosing Relay		
Component Attributes	**Maximum Maintenance Interval**	**Maintenance Activities**
Any unmonitored reclosing relay not having all the monitoring attributes of a category below.	6 Calendar Years	Verify that settings are as specified. For non-microprocessor relays: • Test and, if necessary calibrate For microprocessor relays: • Verify operation of the relay inputs and outputs that are essential to proper functioning of the Automatic Reclosing.
Monitored microprocessor reclosing relay with the following: • Internal self-diagnosis and alarming (See Table 2). • Alarming for power supply failure (See Table 2).	12 Calendar Years	Verify: • Settings are as specified. • Operation of the relay inputs and outputs that are essential to proper functioning of the Automatic Reclosing.

Table 4-2(a) Maintenance Activities and Intervals for Automatic Reclosing Components Component Type – Control Circuitry Associated with Reclosing Relays that are NOT an Integral Part of an RAS		
Component Attributes	**Maximum Maintenance Interval**	**Maintenance Activities**
Unmonitored Control circuitry associated with Automatic Reclosing that is not an integral part of an RAS.	12 Calendar Years	Verify that Automatic Reclosing, upon initiation, does not issue a premature closing command to the close circuitry.
Control circuitry associated with Automatic Reclosing that is not part of an RAS and is monitored and alarmed for conditions that would result in a premature closing command. (See Table 2)	No periodic maintenance specified	None.

Table 4-2(b) Maintenance Activities and Intervals for Automatic Reclosing Components Component Type – Control Circuitry Associated with Reclosing Relays that ARE an Integral Part of an RAS		
Component Attributes	**Maximum Maintenance Interval**	**Maintenance Activities**
Close coils or actuators of circuit breakers or similar devices that are used in conjunction with Automatic Reclosing as part of an RAS (regardless of any monitoring of the control circuitry).	6 Calendar Years	Verify that each close coil or actuator is able to operate the circuit breaker or mitigating device.
Unmonitored close control circuitry associated with Automatic Reclosing used as an integral part of an RAS.	12 Calendar Years	Verify all paths of the control circuits associated with Automatic Reclosing that are essential for proper operation of the RAS.
Control circuitry associated with Automatic Reclosing that is an integral part of an RAS whose integrity is monitored and alarmed. (See Table 2)	No periodic maintenance specified	None.

Table 5

Maintenance Activities and Intervals for Sudden Pressure Relaying

Note: In cases where Components of Sudden Pressure Relaying are common to Components listed in Table 1-5, the Components only need to be tested once during a distinct maintenance interval.

Component Attributes	Maximum Maintenance Interval	Maintenance Activities
Any fault pressure relay.	6 Calendar Years	Verify the pressure or flow sensing mechanism is operable.
Electromechanical lockout devices which are directly in a trip path from the fault pressure relay to the interrupting device trip coil (regardless of any monitoring of the control circuitry).	6 Calendar Years	Verify electrical operation of electromechanical lockout devices.
Unmonitored control circuitry associated with Sudden Pressure Relaying.	12 Calendar Years	Verify all paths of the trip circuits inclusive of all auxiliary relays through the trip coil(s) of the circuit breakers or other interrupting devices.
Control circuitry associated with Sudden Pressure Relaying whose integrity is monitored and alarmed (See Table 2).	No periodic maintenance specified	None.

PRC-005 — Attachment A

Criteria for a Performance-Based Protection System Maintenance Program

Purpose: To establish a technical basis for initial and continued use of a performance-based Protection System Maintenance Program (PSMP).

To establish the technical justification for the initial use of a performance-based PSMP:

1. Develop a list with a description of Components included in each designated Segment, with a minimum Segment population of 60 Components.
2. Maintain the Components in each Segment according to the time-based maximum allowable intervals established in Tables 1-1 through 1-5, Table 3, Tables 4-1 through 4-2, and Table 5 until results of maintenance activities for the Segment are available for a minimum of 30 individual Components of the Segment.
3. Document the maintenance program activities and results for each Segment, including maintenance dates and Countable Events for each included Component.
4. Analyze the maintenance program activities and results for each Segment to determine the overall performance of the Segment and develop maintenance intervals.
5. Determine the maximum allowable maintenance interval for each Segment such that the Segment experiences Countable Events on no more than 4% of the Components within the Segment, for the greater of either the last 30 Components maintained or all Components maintained in the previous year.

To maintain the technical justification for the ongoing use of a performance-based PSMP:

1. At least annually, update the list of Components and Segments and/or description if any changes occur within the Segment.
2. Perform maintenance on the greater of 5% of the Components (addressed in the performance based PSMP) in each Segment or 3 individual Components within the Segment in each year.
3. For the prior year, analyze the maintenance program activities and results for each Segment to determine the overall performance of the Segment.
4. Using the prior year's data, determine the maximum allowable maintenance interval for each Segment such that the Segment experiences Countable Events on no more than 4% of the Components within the Segment, for the greater of either the last 30 Components maintained or all Components maintained in the previous year.

If the Components in a Segment maintained through a performance-based PSMP experience 4% or more Countable Events, develop, document, and implement an action plan to reduce the Countable Events to less than 4% of the Segment population within 3 years.

Rationale:

During development of this standard, text boxes were embedded within the standard to explain the rationale for various parts of the standard. Upon BOT approval, the text from the rationale text boxes was moved to this section.

Rationale for Applicability Section:
This section does not reflect the applicability changes that will be proposed by the Project 2014-01 Standards Applicability for Dispersed Generation Resources standards drafting team. The changes in this posted version and those being made by the Project 2014-01 standards drafting team do not overlap.

Additionally, to align with ongoing NERC standards development in Project 2010-05.2: Special Protection Systems, the term "Special Protection Systems" in PRC-005-4 was replaced by the term "Remedial Action Schemes." These terms are synonymous in the NERC Glossary of Terms.

Rationale for the deletion of part of the definition of Component:
The SDT determined that it was explanatory in nature and adequately addressed in the Supplementary Reference and FAQ Document.

Rationale for R3 Part 3.1:
In the last posting, the SDT included language in the standard that was originally in the implementation plan that required completion of maintenance activities within three years for newly-identified Automatic Reclosing Components following a notification under Requirement R6, which has been removed. After further discussion, the SDT determined that a separate shorter timeframe for maintenance of newly-identified Automatic Reclosing Components created unnecessary complication within the standard. The SDT agreed that entities should be responsible for maintaining the Automatic Reclosing Components subject to the standard, whether existing, newly added or newly within scope based on a change in the largest generating unit in the BA or, if a member of a Reserve Sharing Group, the largest generating unit within the Reserve Sharing Group according to the timeframes in the maintenance tables. Therefore, 3.1 and its subparts have been removed and have not been reinserted into the implementation plan.

Rationale for R4 Part 4.1:
In the last posting, the SDT included language in the standard that was originally in the implementation plan that required completion of maintenance activities within three years for newly-identified Automatic Reclosing Components following a notification under Requirement R6, which has been removed. After further discussion, the SDT determined that a separate shorter timeframe for maintenance of newly-identified Automatic Reclosing Components created unnecessary complication within the standard. The SDT agreed that entities should be responsible for maintaining the Automatic Reclosing Components subject to the standard, whether existing, newly added or newly within scope based on a change in the largest generating unit in the BA or, if a member of a Reserve Sharing Group, the largest generating

unit within the Reserve Sharing Group according to the timeframes in the maintenance tables. Therefore, 4.1 and its subparts have been removed and have not been reinserted into the implementation plan.

A. Introduction

1. **Title: Protection System~~ and~~, Automatic Reclosing, and Sudden Pressure Relaying Maintenance**

2. **Number: PRC-005-~~3~~4**

3. **Purpose:** To document and implement programs for the maintenance of all ~~3. Purpose: To document and implement programs for the maintenance of all~~ Protection Systems~~ and~~, Automatic Reclosing, and Sudden Pressure Relaying affecting the reliability of the Bulk Electric System (BES) so that they are kept in working order.

~~4. Applicability:~~

3.1. ~~4.1.~~ **Functional Entities:**

3.1.1 ~~4.1.1~~ Transmission Owner

3.1.2 ~~4.1.2~~ Generator Owner

3.1.3 ~~4.1.3~~ Distribution Provider

3.2. ~~4.2.~~ **Facilities:**

3.2.1 ~~4.2.1~~ Protection Systems and Sudden Pressure Relaying that are installed for the purpose of detecting Faults on BES Elements (lines, buses, transformers, etc.)

3.2.2 ~~4.2.2~~ Protection Systems used for underfrequency load-shedding systems installed per ERO underfrequency load-shedding requirements.

3.2.3 ~~4.2.3~~ Protection Systems used for undervoltage load-shedding systems installed to prevent system voltage collapse or voltage instability for BES reliability.

3.2.4 ~~4.2.4~~ Protection Systems installed as a ~~Special Protection System (SPS~~Remedial Action Scheme (RAS) for BES reliability.

3.2.5 ~~4.2.5~~ Protection Systems and Sudden Pressure Relaying for generator Facilities that are part of the BES, including:

3.2.5.1 ~~4.2.5.1~~ Protection Systems that act to trip the generator either directly or via lockout or auxiliary tripping relays.

3.2.5.2 ~~4.2.5.2~~ Protection Systems and Sudden Pressure Relaying for generator step-up transformers for generators that are part of the BES.

3.2.5.3 ~~4.2.5.3~~ Protection Systems and Sudden Pressure Relaying for transformers connecting aggregated generation, where the aggregated generation is part of the BES (e.g., transformers connecting facilities such as wind-farms to the BES).

3.2.5.4 ~~4.2.5.4~~ Protection Systems and Sudden Pressure Relaying for station service or excitation transformers connected to the generator bus of generators which are part of the BES, that act to trip the generator either directly or via lockout or tripping auxiliary relays.

3.2.6 ~~4.2.6~~ Automatic Reclosing~~[1]~~,[1] including:

3.2.6.1 ~~4.2.6.1~~ Automatic Reclosing applied on the terminals of Elements connected to the BES bus located at generating plant substations where the total installed gross generating plant capacity is greater than the gross capacity of the largest BES generating unit within the Balancing Authority Area~~.~~ or, if a member of a Reserve Sharing Group, the largest generating unit within the Reserve Sharing Group. [2]

3.2.6.2 ~~4.2.6.2~~ Automatic Reclosing applied on the terminals of all BES Elements at substations one bus away from generating plants specified in Section 4.2.6.1 when the substation is less than 10 circuit-miles from the generating plant substation.

~~4.2.6.3~~ 4.2.6.3. Automatic Reclosing applied as an integral part of an ~~SPS~~RAS specified in Section 4.2.4.

4. ~~5.~~ **Effective Date:** See Implementation Plan

5. ~~6.~~ **Definitions Used in this Standard:** ~~The following terms are defined for use only within PRC-005-3, and should remain with the standard upon approval rather than being moved to the Glossary of Terms.~~

Automatic Reclosing – Includes the following Components:

- Reclosing relay
- Control circuitry associated with the reclosing relay.

~~[1] Automatic Reclosing addressed in Section 4.2.6.1 and 4.2.6.2 may be excluded if the equipment owner can demonstrate that a close-in three-phase fault present for twice the normal clearing time (capturing a minimum trip-close-trip time delay) does not result in a total loss of gross generation in the Interconnection exceeding the gross capacity of the largest BES generating unit within the Balancing Authority Area where the Automatic Reclosing is applied.~~

[1] Automatic Reclosing addressed in Section 4.2.6.1 and 4.2.6.2 may be excluded if the equipment owner can demonstrate that a close-in three-phase fault present for twice the normal clearing time (capturing a minimum trip-close-trip time delay) does not result in a total loss of gross generation in the Interconnection exceeding the gross capacity of the largest relevant BES generating unit where the Automatic Reclosing is applied.

[2] The largest BES generating unit within the Balancing Authority Area or the largest generating unit within the Reserve Sharing Group, as applicable, is subject to change. As a result of such a change, the Automatic Reclosing Components subject to the standard could change effective on the date of such change.

Sudden Pressure Relaying – A system that trips an interrupting device(s) to isolate the equipment it is monitoring and includes the following Components:

- Fault pressure relay – a mechanical relay or device that detects rapid changes in gas pressure, oil pressure, or oil flow that are indicative of Faults within liquid-filled, wire-wound equipment
- Control circuitry associated with a fault pressure relay

Unresolved Maintenance Issue – A deficiency identified during a maintenance activity that causes the Component to not meet the intended performance, cannot be corrected during the maintenance interval, and requires follow-up corrective action.

Segment – Components of a consistent design standard, or a particular model or type from a single manufacturer that typically share other common elements. Consistent performance is expected across the entire population of a Segment. A Segment must contain at least sixty (60) individual Components.

Component Type –

- Any one of the five specific elements of a Protection System.
- ~~**Component Type** – Either any one of the five specific elements of the Protection System definition or any~~Any one of the two specific elements of~~ the~~ Automatic Reclosing ~~definition~~.
- Any one of the two specific elements of Sudden Pressure Relaying.

Component – ~~A Component is any~~Any individual discrete piece of equipment included in a Protection System~~ or in~~, Automatic Reclosing, ~~including but not limited to a protective relay, reclosing relay, or current sensing device. The designation of what constitutes a control circuit Component is dependent upon how an entity performs and tracks the testing of the control circuitry. Some entities test their control circuits on a breaker basis whereas others test their circuitry on a local zone of protection basis. Thus, entities are allowed the latitude to designate their own definitions of control circuit Components. Another example of where the entity has some discretion on determining what constitutes a single Component is the voltage and current sensing devices, where the entity may choose either to designate a full three-phase set of such devices or a single device as a single Component.~~or Sudden Pressure Relaying.

Countable Event – A failure of a Component requiring repair or replacement, any condition discovered during the maintenance activities in Tables 1-1 through 1-5, Table 3, ~~and~~ Tables 4-1 through 4-~~2~~2, and Table 5, which requires corrective action or a Protection System Misoperation attributed to hardware failure or calibration failure. Misoperations due to product design errors, software errors, relay settings different from specified settings, Protection System Component~~ or~~, Automatic Reclosing, or Sudden Pressure Relaying configuration or application errors are not included in Countable Events.

B. Requirements and Measures

R1. Each Transmission Owner, Generator Owner, and Distribution Provider shall establish a Protection System Maintenance Program (PSMP) for its Protection Systems~~and~~, Automatic Reclosing, and Sudden Pressure Relaying identified in Section 4.2, Facilities ~~Section 4.2.~~. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning*]

The PSMP shall:

1.1. Identify which maintenance method (time-based, performance-based per PRC-005 Attachment A, or a combination) is used to address each Protection System ~~and~~, Automatic Reclosing, and Sudden Pressure Relaying Component Type. All batteries associated with the station dc supply Component Type of a Protection System shall be included in a time-based program as described in Table 1-4 and Table 3.

1.2. Include the applicable monitored Component attributes applied to each Protection System~~and~~, Automatic Reclosing, and Sudden Pressure Relaying Component Type consistent with the maintenance intervals specified in Tables 1-1 through 1-5, Table 2, Table 3, ~~and~~ Table 4-1 through 4-~~2~~2, and Table 5 where monitoring is used to extend the maintenance intervals beyond those specified for unmonitored Protection System~~and~~, Automatic Reclosing, and Sudden Pressure Relaying Components.

~~**R2.** Each Transmission Owner, Generator Owner, and Distribution Provider that uses performance-based maintenance intervals in its PSMP shall follow the procedure established in PRC-005 Attachment A to establish and maintain its performance-based intervals. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*~~

~~**R3.** Each Transmission Owner, Generator Owner, and Distribution Provider that utilizes time-based maintenance program(s) shall maintain its Protection System and Automatic Reclosing Components that are included within the time-based maintenance program in accordance with the minimum maintenance activities and maximum maintenance intervals prescribed within Tables 1-1 through 1-5, Table 2, Table 3, and Table 4-1 through 4-2. *[Violation Risk Factor: High] [Time Horizon: Operations Planning]*~~

~~**R4.** Each Transmission Owner, Generator Owner, and Distribution Provider that utilizes performance-based maintenance program(s) in accordance with Requirement R2 shall implement and follow its PSMP for its Protection System and Automatic Reclosing Components that are included within the performance-based program(s). *[Violation Risk Factor: High] [Time Horizon: Operations Planning]*~~

~~**R5.** Each Transmission Owner, Generator Owner, and Distribution Provider shall demonstrate efforts to correct identified Unresolved Maintenance Issues. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*~~

~~C. Measures~~

M1. Each Transmission Owner, Generator Owner and Distribution Provider shall have a documented Protection System Maintenance Program in accordance with Requirement R1.

For each Protection System ~~and~~, Automatic Reclosing, and Sudden Pressure Relaying Component Type, the documentation shall include the type of maintenance method applied (time-based, performance-based, or a combination of these maintenance methods), and shall include all batteries associated with the station dc supply Component Types in a time-based program as described in Table 1-4 and Table 3. (Part 1.1)

For Component Types that use monitoring to extend the maintenance intervals, the responsible entity(s) shall have evidence for each Protection System ~~and~~, Automatic Reclosing, and Sudden Pressure Relaying Component Type (such as manufacturer's specifications or engineering drawings) of the appropriate monitored Component attributes as specified in Tables 1-1 through 1-5, Table 2, Table 3, ~~and~~ Table 4-1 through 4-~~2.~~2, and Table 5. (Part 1.2)

R2. Each Transmission Owner, Generator Owner, and Distribution Provider that uses performance-based maintenance intervals in its PSMP shall follow the procedure established in PRC-005 Attachment A to establish and maintain its performance-based intervals. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

M2. ~~Each Transmission Owner,~~ Each Transmission Owner, Generator Owner, and Distribution Provider that uses performance-based maintenance intervals shall have evidence that its current performance-based maintenance program(s) is in accordance with Requirement R2, which may include, but is not limited to, Component lists, dated maintenance records, and dated analysis records and results.

R3. Each Transmission Owner, Generator Owner, and Distribution Provider that utilizes time-based maintenance program(s) shall maintain its Protection System, Automatic Reclosing, and Sudden Pressure Relaying Components that are included within the time-based maintenance program in accordance with the minimum maintenance activities and maximum maintenance intervals prescribed within Tables 1-1 through 1-5, Table 2, Table 3, Table 4-1 through 4-2, and Table 5. *[Violation Risk Factor: High] [Time Horizon: Operations Planning]*

M3. ~~Each Transmission Owner, Generator Owner, and Distribution Provider that utilizes time-based maintenance program(s) shall~~ Each Transmission Owner, Generator Owner, and Distribution Provider that utilizes time-based maintenance program(s) shall have evidence that it has maintained its Protection System ~~and~~, Automatic Reclosing, and Sudden Pressure Relaying Components included within its time-based program in accordance with Requirement R3. The evidence may include, but is not limited to, dated maintenance records, dated maintenance summaries, dated check-off lists, dated inspection records, or dated work orders.

R4. Each Transmission Owner, Generator Owner, and Distribution Provider that utilizes performance-based maintenance program(s) in accordance with Requirement R2 shall implement and follow its PSMP for its Protection System, Automatic Reclosing, and Sudden Pressure Relaying Components that are included within the performance-based program(s). *[Violation Risk Factor: High] [Time Horizon: Operations Planning]*

M4. Each Transmission Owner, Generator Owner, and Distribution Provider that utilizes performance-based maintenance intervals in accordance with Requirement R2 shall have evidence that it has implemented the Protection System Maintenance Program for the Protection System ~~and~~, Automatic Reclosing, and Sudden Pressure Relaying Components included in its performance-based program in accordance with Requirement R4. The evidence may include, but is not limited to, dated maintenance records, dated maintenance summaries, dated check-off lists, dated inspection records, or dated work orders.

R5. Each Transmission Owner, Generator Owner, and Distribution Provider shall demonstrate efforts to correct identified Unresolved Maintenance Issues. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

M5. Each Transmission Owner, Generator Owner, and Distribution Provider shall have evidence that it has undertaken efforts to correct identified Unresolved Maintenance Issues in accordance with Requirement R5. The evidence may include, but is not limited to, work orders, replacement Component orders, invoices, project schedules with completed milestones, return material authorizations (RMAs) or purchase orders.

C. ~~D.~~ Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

As defined in the NERC Rules of Procedure, "Compliance Enforcement Authority" means NERC or the Regional Entity in their respective roles of monitoring and enforcing compliance with the NERC Reliability Standards.

~~1.2. Compliance Monitoring and Enforcement Processes:~~

~~Compliance Audit~~

~~Self-Certification~~

~~Spot Checking~~

~~Compliance Investigation~~

~~Self-Reporting~~

~~Complaint~~

1.2. ~~1.3.~~ Evidence Retention

The following evidence retention periods identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

The Transmission Owner, Generator Owner, and Distribution Provider shall each keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

For Requirement R1, the Transmission Owner, Generator Owner, and Distribution Provider shall each keep its current dated Protection System Maintenance

Program, as well as any superseded versions since the preceding compliance audit, including the documentation that specifies the type of maintenance program applied for each Protection System, Automatic Reclosing, or Sudden Pressure Relaying Component Type.

For Requirement R2, Requirement R3, and Requirement R4, ~~and Requirement R5,~~in cases where the interval of the maintenance activity is longer than the audit cycle, the Transmission Owner, Generator Owner, and Distribution Provider shall each keep documentation of the ~~two~~ most recent ~~performances of each distinct~~performance of that maintenance activity for the Protection System ~~or~~, Automatic Reclosing ~~Component, or all performances of each distinct~~, or Sudden Pressure Relaying Component. In cases where the interval of the maintenance activity is shorter than the audit cycle, documentation of all performances (in accordance with the tables) of that maintenance activity for the Protection System ~~or~~, Automatic Reclosing, or Sudden Pressure Relaying Component since the previous scheduled audit date~~, whichever is longer~~ shall be retained.
For Requirement R5 the Transmission Owner, Generator Owner, and Distribution Provider shall each keep documentation of Unresolved Maintenance Issues identified by the entity since the last audit, including all that were resolved since the last audit.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.3. Compliance Monitoring and Assessment Processes:

Compliance Audits

Self-Certifications

Spot Checking

Compliance Violation Investigations

Self-Reporting

Complaints

1.4. Additional Compliance Information

None~~.~~

Table of Compliance Elements~~2. Violation Severity Levels~~

R1	The ~~responsible~~ entity's PSMP failed to specify whether one Component Type is being addressed by time-based or performance-based maintenance, or a combination of both~~.~~ (Part 1.1).	The ~~responsible~~ entity's PSMP failed to specify whether two Component Types are being addressed by time-based or performance-based maintenance, or a combination of both~~.~~ (Part 1.1).	The ~~responsible~~ entity's PSMP failed to specify whether three Component Types are being addressed by time-based or performance-based maintenance, or a combination of both. (Part 1.1). OR The ~~responsible~~ entity's PSMP failed to include the applicable monitoring attributes applied to each Component Type consistent with the maintenance intervals specified in Tables 1-1 through 1-5, Table 2, Table 3, ~~and~~ Tables 4-1 through 4-~~2~~2, and Table 5 where monitoring is used to extend the maintenance intervals beyond those specified for unmonitored Components~~.~~ (Part 1.2).	The ~~responsible~~ entity failed to establish a PSMP. OR The ~~responsible~~ entity's PSMP failed to specify whether four or more Component Types are being addressed by time-based or performance-based maintenance, or a combination of both~~.~~ (Part 1.1). OR The ~~responsible~~ entity's PSMP failed to include applicable station batteries in a time-based program~~.~~ (Part 1.1).
R2	The ~~responsible~~ entity uses performance-based maintenance intervals in its PSMP but failed to reduce Countable Events to no more than 4% within three years.	NA	The ~~responsible~~ entity uses performance-based maintenance intervals in its PSMP but failed to reduce Countable Events to no more than 4% within four years.	The ~~responsible~~ entity uses performance-based maintenance intervals in its PSMP but: 1) Failed to establish the technical justification described within Requirement R2 for the initial use of the performance-based PSMP OR 2) Failed to reduce Countable Events to no more than 4% within five years OR 3) Maintained a Segment with less

				than 60 Components OR 4) Failed to: • Annually update the list of Components, OR • Annually perform maintenance on the greater of 5% of the Segment population or 3 Components, OR • Annually analyze the program activities and results for each Segment.
R3	For Components included within a time-based maintenance program, the ~~responsible~~ entity failed to maintain 5% or less of the total Components included within a specific Component Type~~,~~ in accordance with the minimum maintenance activities and maximum maintenance intervals prescribed within Tables 1-1 through 1-5, Table 2, Table 3, ~~and~~ Tables 4-1 through 4-~~2.~~2, and Table 5.	For Components included within a time-based maintenance program, the ~~responsible~~ entity failed to maintain more than 5% but 10% or less of the total Components included within a specific Component Type~~,~~ in accordance with the minimum maintenance activities and maximum maintenance intervals prescribed within Tables 1-1 through 1-5, Table 2, Table 3, ~~and~~ Tables 4-1 through 4-~~2.~~2, and Table 5.	For Components included within a time-based maintenance program, the ~~responsible~~ entity failed to maintain more than 10% but 15% or less of the total Components included within a specific Component Type~~,~~ in accordance with the minimum maintenance activities and maximum maintenance intervals prescribed within Tables 1-1 through 1-5, Table 2, Table 3, ~~and~~ Tables 4-1 through 4-~~2.~~2, and Table 5.	For Components included within a time-based maintenance program, the ~~responsible~~ entity failed to maintain more than 15% of the total Components included within a specific Component Type~~,~~ in accordance with the minimum maintenance activities and maximum maintenance intervals prescribed within Tables 1-1 through 1-5, Table 2, Table 3, ~~and~~ Tables 4-1 through 4-~~2.~~2, and Table 5.
R4	For Components included within a	For Components included within a	For Components included within a	For Components included within a

	performance-based maintenance program, the ~~responsible~~ entity failed to maintain 5% or less of the annual scheduled maintenance for a specific Component Type in accordance with their performance-based PSMP.	performance-based maintenance program, the ~~responsible~~ entity failed to maintain more than 5% but 10% or less of the annual scheduled maintenance for a specific Component Type in accordance with their performance-based PSMP.	performance-based maintenance program, the ~~responsible~~ entity failed to maintain more than 10% but 15% or less of the annual scheduled maintenance for a specific Component Type in accordance with their performance-based PSMP.	performance-based maintenance program, the ~~responsible~~ entity failed to maintain more than 15% of the annual scheduled maintenance for a specific Component Type in accordance with their performance-based PSMP.
R5	The ~~responsible~~ entity failed to undertake efforts to correct 5 or fewer identified Unresolved Maintenance Issues.	The ~~responsible~~ entity failed to undertake efforts to correct greater than ~~5,~~5 but less than or equal to 10 identified Unresolved Maintenance Issues.	The ~~responsible~~ entity failed to undertake efforts to correct greater than ~~10,~~10 but less than or equal to 15 identified Unresolved Maintenance Issues.	The ~~responsible~~ entity failed to undertake efforts to correct greater than 15 identified Unresolved Maintenance Issues.

D. ~~E.~~ Regional Variances

None.

E. Interpretations

None.

~~F.~~ Supplemental Reference ~~Document~~Documents

The following documents present a detailed discussion about determination of maintenance intervals and other useful information regarding establishment of a maintenance program.

1. *Supplementary Reference and FAQ - PRC-005-~~2~~4 Protection System Maintenance* ~~Supplementary Reference and FAQ — March 2013.~~, Protection System Maintenance and Testing Standard Drafting Team (April 2014)
2. *Considerations for Maintenance and Testing of* ~~Autoreclosing Schemes — November 2012.~~*Auto-reclosing Schemes*, NERC System Analysis and Modeling Subcommittee, and NERC System Protection and Control Subcommittee (November 2012)
3. *Sudden Pressure Relays and Other Devices that Respond to Non-Electrical Quantities – SPCS Input for Standard Development in Response to FERC Order No. 758*, NERC System Protection and Control Subcommittee (December 2013)

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
1	December 1, 2005	1. Changed incorrect use of certain hyphens (-) to “en dash” (–) and “em dash (—).” 2. Added “periods” to items where appropriate. 3. Changed “Timeframe” to “Time Frame” in item D, 1.2.	01/20/05
1a	February 17, 2011	Added Appendix 1 - Interpretation regarding applicability of standard to protection of radially connected transformers	Project 2009-17 interpretation
1a	February 17, 2011	Adopted by Board of Trustees	
1a	September 26, 2011	FERC Order issued approving interpretation of R1 and R2 (FERC’s Order is effective as of September 26, 2011)	
~~1.1a~~	~~February 1, 2012~~	~~Errata change: Clarified inclusion of generator interconnection Facility in Generator Owner’s responsibility~~	~~Revision under Project 2010-07~~

1b	February 3, 2012	FERC Order issued approving interpretation of R1, R1.1, and R1.2 (FERC's Order dated March 14, 2012). Updated version from 1a to 1b.	Project 2009-10 Interpretation
1.1b	April 23, 2012	Updated standard version to 1.1b to reflect FERC approval of PRC-005-1b.	Revision under Project 2010-07
1.1b	May 9, 2012	PRC-005-1.1b was adopted by the Board of Trustees as part of Project 2010-07 (~~GOTO~~Generator Requirements at the Transmission Interface).	
2	November 7, 2012	Adopted by Board of Trustees	Project 2007-17 - Complete revision, absorbing maintenance requirements from PRC-005-1.1b, PRC-008-0, PRC-011-0, PRC-017-0
2	October 17, 2013	Errata Change: The Standards Committee approved an errata change to the implementation plan for PRC-005-2 to add the phrase "or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities;" to the second sentence under the "Retirement of Existing	
2(i)	November 13, 2014	Adopted by the NERC Board of Trustees	
2(ii)	November 13, 2014	Adopted by the NERC Board of Trustees	

3	November 7, 2013	Adopted by the NERC Board of Trustees	Revised to address the FERC directive in Order No.758 to include Automatic Reclosing in maintenance programs.
3	February 12, 2014	Approved by ~~NERC~~the Standards Committee	Errata ~~Change: The Standards Committee approved errata~~ changes to correct capitalization of ~~certain defined terms within the definitions of "Unresolved Maintenance Issue" and "Protection System Maintenance Program". The changes will be reflected in the definitions section of PRC-005-3 for "Unresolved Maintenance Issue" and in the NERC Glossary of Terms for "Protection System Maintenance Program".~~defined terms (no change to numbering of standard ~~version number~~as a result)
3(i)	November 13, 2014	Adopted by the NERC Board of Trustees	
3(ii)	November 13, 2014	Adopted by the NERC Board of Trustees	
4	November 13, 2014	Adopted by the NERC Board of Trustees	Project 2007-17.3 – Revised to address the FERC directive in Order No. 758 to include sudden pressure relays in maintenance programs.
~~3~~	~~March 7, 2014~~	~~Adopted by NERC Board of Trustees~~	~~Modified R1 VSL in response to FERC directive (no change to standard version number)~~

	~~2~~3	
ay not having all the monitoring attributes of	6 Calendar Years	For all unmonitored relays: • Verify that settings are as specified For non-microprocessor relays: • Test and, if necessary calibrate For microprocessor relays: • Verify operation of the relay inputs and outputs that are essential to proper functioning of the Protection System. • Verify acceptable measurement of power system input values.
ective relay with the following: alarming (see Table 2). veform sampling three or more times per on of samples to numeric values for by microprocessor electronics. failure (see Table 2).	12 Calendar Years	Verify: • Settings are as specified. • Operation of the relay inputs and outputs that are essential to proper functioning of the Protection System. • Acceptable measurement of power system input values.
tective relay with preceding row attributes inuously verified by comparison to an	12 Calendar Years	Verify only the unmonitored relay inputs and outputs that are essential to proper functioning of the Protection System.

	~~2~~3	
independent ac measurement source, with alarming for excessive error (See Table 2). • Some or all binary or status inputs and control outputs are monitored by a process that continuously demonstrates ability to perform as designed, with alarming for failure (See Table 2). • Alarming for change of settings (See Table 2).		

Any unmonitored communications system necessary for correct operation of protective functions, and not having all the monitoring attributes of a category below.	4 Calendar Months	Verify that the communications system is functional.
	6 Calendar Years	Verify that the communications system meets performance criteria pertinent to the communications technology applied (e.g. signal level, reflected power, or data error rate). Verify operation of communications system inputs and outputs that are essential to proper functioning of the Protection System.
Any communications system with continuous monitoring or periodic automated testing for the presence of the channel function, and alarming for loss of function (See Table 2).	12 Calendar Years	Verify that the communications system meets performance criteria pertinent to the communications technology applied (e.g. signal level, reflected power, or data error rate). Verify operation of communications system inputs and outputs that are essential to proper functioning of the Protection System.
Any communications system with all of the following: • Continuous monitoring or periodic automated testing for the performance of the channel using criteria pertinent to the communications technology applied (e.g. signal level, reflected power, or data error rate, and alarming for excessive performance degradation). (See Table 2) • Some or all binary or status inputs and control outputs are monitored by a process that continuously demonstrates ability to perform as designed, with alarming for failure (See Table 2).	12 Calendar Years	Verify only the unmonitored communications system inputs and outputs that are essential to proper functioning of the Protection System

Table 1-3 Component Type - Voltage and Current Sensing Devices Providing Inputs to Protective Relays Excluding distributed UFLS and distributed UVLS (see Table 3)		
Component Attributes	**Maximum Maintenance Interval**	**Maintenance Activities**
Any voltage and current sensing devices not having monitoring attributes of the category below.	12 Calendar Years	Verify that current and voltage signal values are provided to the protective relays.
Voltage and Current Sensing devices connected to microprocessor relays with AC measurements are continuously verified by comparison of sensing input value, as measured by the microprocessor relay, to an independent ac measurement source, with alarming for unacceptable error or failure (see Table 2).	No periodic maintenance specified	None.

~~Table 1-3~~ ~~Component Type - Voltage and Current Sensing Devices Providing Inputs to Protective Relays~~ ~~Excluding distributed UFLS and distributed UVLS (see Table 3)~~		
~~**Component Attributes**~~	~~**Maximum Maintenance Interval**~~	~~**Maintenance Activities**~~
~~Any voltage and current sensing devices not having monitoring attributes of the category below.~~	~~12 Calendar Years~~	~~Verify that current and voltage signal values are provided to the protective relays.~~

~~Voltage and Current Sensing devices connected to microprocessor relays with AC measurements are continuously verified by comparison of sensing input value, as measured by the microprocessor relay, to an independent ac measurement source, with alarming for unacceptable error or failure (see Table 2).~~	~~No periodic maintenance specified~~	~~None.~~

		~~SPS~~RAS
Protection System Station dc supply using Vented Lead-Acid (VLA) batteries not having monitoring attributes of Table 1-4(f).	4 Calendar Months	Verify: • Station dc supply voltage Inspect: • Electrolyte level • For unintentional grounds
	18 Calendar Months	Verify: • Float voltage of battery charger • Battery continuity • Battery terminal connection resistance • Battery intercell or unit-to-unit connection resistance Inspect: • Cell condition of all individual battery cells where cells are visible – or measure battery cell/unit internal ohmic values where the cells are not visible • Physical condition of battery rack
	18 Calendar Months	Verify that the station battery can perform as manufactured by

~~SPS~~RAS		
	-or- 6 Calendar Years	evaluating cell/unit measurements indicative of battery performance (e.g. internal ohmic values or float current) against the station battery baseline. -or- Verify that the station battery can perform as manufactured by conducting a performance or modified performance capacity test of the entire battery bank.

		~~SPS~~RAS
Protection System Station dc supply with Valve Regulated Lead-Acid (VRLA) batteries not having monitoring attributes of Table 1-4(f).	4 Calendar Months	Verify: • Station dc supply voltage Inspect: • For unintentional grounds
	6 Calendar Months	Inspect: • Condition of all individual units by measuring battery cell/unit internal ohmic values.
	18 Calendar Months	Verify: • Float voltage of battery charger • Battery continuity • Battery terminal connection resistance • Battery intercell or unit-to-unit connection resistance Inspect: • Physical condition of battery rack

~~SPS~~RAS		
	6 Calendar Months -or- 3 Calendar Years	Verify that the station battery can perform as manufactured by evaluating cell/unit measurements indicative of battery performance (e.g. internal ohmic values or float current) against the station battery baseline. -or- Verify that the station battery can perform as manufactured by conducting a performance or modified performance capacity test of the entire battery bank.

~~SPS~~RAS		
Protection System Station dc supply **Nickel-Cadmium (NiCad) batteries** not having monitoring attributes of Table 1-4(f).	4 Calendar Months	Verify: • Station dc supply voltage Inspect: • Electrolyte level • For unintentional grounds
	18 Calendar Months	Verify: • Float voltage of battery charger • Battery continuity • Battery terminal connection resistance • Battery intercell or unit-to-unit connection resistance Inspect: • Cell condition of all individual battery cells. • Physical condition of battery rack
	6 Calendar Years	Verify that the station battery can perform as manufactured by conducting a performance or modified performance capacity test of the entire battery bank.

~~SPS~~RAS		
Any Protection System station dc supply not using a battery and not having monitoring attributes of Table 1-4(f).	4 Calendar Months	Verify: • Station dc supply voltage Inspect: • For unintentional grounds
	18 Calendar Months	Inspect: Condition of non-battery based dc supply
	6 Calendar Years	Verify that the dc supply can perform as manufactured when ac power is not present.

~~SPS~~RAS		
Any Protection System dc supply used for tripping only non-BES interrupting devices as part of a ~~SPS~~RAS, non-distributed UFLS, or non-distributed UVLS system and not having monitoring attributes of Table 1-4(f).	When control circuits are verified (See Table 1-5)	Verify Station dc supply voltage.

Any station dc supply with high and low voltage monitoring and alarming of the battery charger voltage to detect charger overvoltage and charger failure (See Table 2).	No periodic maintenance specified	No periodic verification of station dc supply voltage is required.
Any battery based station dc supply with electrolyte level monitoring and alarming in every cell (See Table 2).		No periodic inspection of the electrolyte level for each cell is required.
Any station dc supply with unintentional dc ground monitoring and alarming (See Table 2).		No periodic inspection of unintentional dc grounds is required.
Any station dc supply with charger float voltage monitoring and alarming to ensure correct float voltage is being applied on the station dc supply (See Table 2).		No periodic verification of float voltage of battery charger is required.
Any battery based station dc supply with monitoring and alarming of battery string continuity (See Table 2).		No periodic verification of the battery continuity is required.
Any battery based station dc supply with monitoring and alarming of the intercell and/or terminal connection detail resistance of the entire battery (See Table 2).		No periodic verification of the intercell and terminal connection resistance is required.
Any Valve Regulated Lead-Acid (VRLA) or Vented Lead-Acid (VLA) station battery with internal ohmic value or float current monitoring and alarming, and evaluating present values relative to baseline internal ohmic values for every cell/unit (See Table 2).		No periodic evaluation relative to baseline of battery cell/unit measurements indicative of battery performance is required to verify the station battery can perform as manufactured.
Any Valve Regulated Lead-Acid (VRLA) or Vented Lead-Acid (VLA) station battery with monitoring and alarming of each cell/unit internal ohmic value (See Table 2).		No periodic inspection of the condition of all individual units by measuring battery cell/unit internal ohmic values of a station VRLA or Vented Lead-Acid (VLA) battery is required.

), Automatic Reclosing (see Table 4), and Sudden Pressure Relaying (see Table 5 ~~SPSs~~RAS		
Trip coils or actuators of circuit breakers, interrupting devices, or mitigating devices (regardless of any monitoring of the control circuitry).	6 Calendar Years	Verify that each trip coil is able to operate the circuit breaker, interrupting device, or mitigating device.
Electromechanical lockout devices which are directly in a trip path from the protective relay to the interrupting device trip coil (regardless of any monitoring of the control circuitry).	6 Calendar Years	Verify electrical operation of electromechanical lockout devices.
Unmonitored control circuitry associated with ~~SPS~~RAS. (See Table 4-2(b) for ~~SPS~~RAS which include Automatic Reclosing.)	12 Calendar Years	Verify all paths of the control circuits essential for proper operation of the ~~SPS~~RAS.
Unmonitored control circuitry associated with protective functions inclusive of all auxiliary relays.	12 Calendar Years	Verify all paths of the trip circuits inclusive of all auxiliary relays through the trip coil(s) of the circuit breakers or other interrupting devices.
Control circuitry associated with protective functions and/or ~~SPSs~~RAS whose integrity is monitored and alarmed (See Table 2).	No periodic maintenance specified	None.

~~and~~ and Table 5		
Any alarm path through which alarms in Tables 1-1 through 1-5, Table 3, ~~and~~ Tables 4-1 through 4-~~2~~2, and Table 5 are conveyed from the alarm origin to the location where corrective action can be initiated, and not having all the attributes of the "Alarm Path with monitoring" category below. Alarms are reported within 24 hours of detection to a location where corrective action can be initiated.	12 Calendar Years	Verify that the alarm path conveys alarm signals to a location where corrective action can be initiated.
Alarm Path with monitoring: The location where corrective action is taken receives an alarm within 24 hours for failure of any portion of the alarming path from the alarm origin to the location where corrective action can be initiated.	No periodic maintenance specified	None.

Any unmonitored protective relay not having all the monitoring attributes of a category below.	6 Calendar Years	Verify that settings are as specified. For non-microprocessor relays: • Test and, if necessary calibrate. For microprocessor relays: • Verify operation of the relay inputs and outputs that are essential to proper functioning of the Protection System. • Verify acceptable measurement of power system input values.
Monitored microprocessor protective relay with the following: • Internal self -diagnosis and alarming (See Table 2). • Voltage and/or current waveform sampling three or more times per power cycle, and conversion of samples to numeric values for measurement calculations by microprocessor electronics. Alarming for power supply failure (See Table 2).	12 Calendar Years	Verify: • Settings are as specified. • Operation of the relay inputs and outputs that are essential to proper functioning of the Protection System. • Acceptable measurement of power system input values
Monitored microprocessor protective relay with preceding row attributes and the following: • Ac measurements are continuously verified by comparison to an independent ac measurement source, with alarming for excessive error (See Table 2). • Some or all binary or status inputs and control outputs are monitored by a process that continuously demonstrates ability to perform as designed, with alarming for failure (See Table 2).	12 Calendar Years	Verify only the unmonitored relay inputs and outputs that are essential to proper functioning of the Protection System.

Alarming for change of settings (See Table 2).		
Voltage and/or current sensing devices associated with UFLS or UVLS systems.	12 Calendar Years	Verify that current and/or voltage signal values are provided to the protective relays.
Protection System dc supply for tripping non-BES interrupting devices used only for a UFLS or UVLS system.	12 Calendar Years	Verify Protection System dc supply voltage.
Control circuitry between the UFLS or UVLS relays and electromechanical lockout and/or tripping auxiliary devices (excludes non-BES interrupting device trip coils).	12 Calendar Years	Verify the path from the relay to the lockout and/or tripping auxiliary relay (including essential supervisory logic).
Electromechanical lockout and/or tripping auxiliary devices associated only with UFLS or UVLS systems (excludes non-BES interrupting device trip coils).	12 Calendar Years	Verify electrical operation of electromechanical lockout and/or tripping auxiliary devices.
Control circuitry between the electromechanical lockout and/or tripping auxiliary devices and the non-BES interrupting devices in UFLS or UVLS systems, or between UFLS or UVLS relays (with no interposing electromechanical lockout or auxiliary device) and the non-BES interrupting devices (excludes non-BES interrupting device trip coils).	No periodic maintenance specified	None.
Trip coils of non-BES interrupting devices in UFLS or UVLS systems.	No periodic maintenance specified	None.

Any unmonitored reclosing relay not having all the monitoring attributes of a category below.	6 Calendar Years	Verify that settings are as specified. For non-microprocessor relays: • Test and, if necessary calibrate For microprocessor relays: • Verify operation of the relay inputs and outputs that are essential to proper functioning of the Automatic Reclosing.
Monitored microprocessor reclosing relay with the following: • Internal self -diagnosis and alarming (See Table 2). • Alarming for power supply failure (See Table 2).	12 Calendar Years	Verify: • Settings are as specified. • Operation of the relay inputs and outputs that are essential to proper functioning of the Automatic Reclosing.

~~SPS~~RAS		
Unmonitored Control circuitry associated with Automatic Reclosing that is not an integral part of an ~~SPS~~RAS.	12 Calendar Years	Verify that Automatic Reclosing, upon initiation, does not issue a premature closing command to the close circuitry.
Control circuitry associated with Automatic Reclosing that is not part of an ~~SPS~~RAS and is monitored and alarmed for conditions that would result in a premature closing command. (See Table 2)	No periodic maintenance specified	None.

		~~SPS~~RAS
Close coils or actuators of circuit breakers or similar devices that are used in conjunction with Automatic Reclosing as part of an ~~SPS~~RAS (regardless of any monitoring of the control circuitry).	6 Calendar Years	Verify that each close coil or actuator is able to operate the circuit breaker or mitigating device.
Unmonitored close control circuitry associated with Automatic Reclosing used as an integral part of an ~~SPS~~RAS.	12 Calendar Years	Verify all paths of the control circuits associated with Automatic Reclosing that are essential for proper operation of the ~~SPS~~RAS.
Control circuitry associated with Automatic Reclosing that is an integral part of an ~~SPS~~RAS whose integrity is monitored and alarmed. (See Table 2)	No periodic maintenance specified	None.

Table 5

Maintenance Activities and Intervals for Sudden Pressure Relaying

Note: In cases where Components of Sudden Pressure Relaying are common to Components listed in Table 1-5, the Components only need to be tested once during a distinct maintenance interval.

Component Attributes	Maximum Maintenance Interval	Maintenance Activities
Any fault pressure relay.	6 Calendar Years	Verify the pressure or flow sensing mechanism is operable.
Electromechanical lockout devices which are directly in a trip path from the fault pressure relay to the interrupting device trip coil (regardless of any monitoring of the control circuitry).	6 Calendar Years	Verify electrical operation of electromechanical lockout devices.
Unmonitored control circuitry associated with Sudden Pressure Relaying.	12 Calendar Years	Verify all paths of the trip circuits inclusive of all auxiliary relays through the trip coil(s) of the circuit breakers or other interrupting devices.
Control circuitry associated with Sudden Pressure Relaying whose integrity is monitored and alarmed (See Table 2).	No periodic maintenance specified	None.

Rationale:

During development of this standard, text boxes were embedded within the standard to explain the rationale for various parts of the standard. Upon BOT approval, the text from the rationale text boxes was moved to this section.

Rationale for Applicability Section:
This section does not reflect the applicability changes that will be proposed by the Project 2014-01 Standards Applicability for Dispersed Generation Resources standards drafting team. The changes in this posted version and those being made by the Project 2014-01 standards drafting team do not overlap.

Additionally, to align with ongoing NERC standards development in Project 2010-05.2: Special Protection Systems, the term "Special Protection Systems" in PRC-005-4 was replaced by the term "Remedial Action Schemes." These terms are synonymous in the NERC Glossary of Terms.

Rationale for the deletion of part of the definition of Component:
The SDT determined that it was explanatory in nature and adequately addressed in the Supplementary Reference and FAQ Document.

Rationale for R3 Part 3.1:
In the last posting, the SDT included language in the standard that was originally in the implementation plan that required completion of maintenance activities within three years for newly-identified Automatic Reclosing Components following a notification under Requirement R6, which has been removed. After further discussion, the SDT determined that a separate shorter timeframe for maintenance of newly-identified Automatic Reclosing Components created unnecessary complication within the standard. The SDT agreed that entities should be responsible for maintaining the Automatic Reclosing Components subject to the standard, whether existing, newly added or newly within scope based on a change in the largest generating unit in the BA or, if a member of a Reserve Sharing Group, the largest generating unit within the Reserve Sharing Group according to the timeframes in the maintenance tables. Therefore, 3.1 and its subparts have been removed and have not been reinserted into the implementation plan.

Rationale for R4 Part 4.1:
In the last posting, the SDT included language in the standard that was originally in the implementation plan that required completion of maintenance activities within three years for newly-identified Automatic Reclosing Components following a notification under Requirement R6, which has been removed. After further discussion, the SDT determined that a separate shorter timeframe for maintenance of newly-identified Automatic Reclosing Components created unnecessary complication within the standard. The SDT agreed that entities should be responsible for maintaining the Automatic Reclosing Components subject to the standard, whether existing, newly added or newly within scope based on a change in the largest generating unit in the BA or, if a member of a Reserve Sharing Group, the largest generating unit within the Reserve Sharing Group according to the timeframes in the maintenance tables. Therefore, 4.1 and its subparts have been removed and have not been reinserted into the implementation plan.

PRC-005 — Attachment A

Criteria for a Performance-Based Protection System Maintenance Program

Purpose: To establish a technical basis for initial and continued use of a performance-based Protection System Maintenance Program (PSMP).

To establish the technical justification for the initial use of a performance-based PSMP:

1. Develop a list with a description of Components included in each designated Segment, with a minimum Segment population of 60 Components.
2. Maintain the Components in each Segment according to the time-based maximum allowable intervals established in Tables 1-1 through 1-5, Table 3, ~~and~~ Tables 4-1 through 4-~~2~~2, and Table 5 until results of maintenance activities for the Segment are available for a minimum of 30 individual Components of the Segment.
3. Document the maintenance program activities and results for each Segment, including maintenance dates and Countable Events for each included Component.
4. Analyze the maintenance program activities and results for each Segment to determine the overall performance of the Segment and develop maintenance intervals.
5. Determine the maximum allowable maintenance interval for each Segment such that the Segment experiences Countable Events on no more than 4% of the Components within the Segment, for the greater of either the last 30 Components maintained or all Components maintained in the previous year.

To maintain the technical justification for the ongoing use of a performance-based PSMP:

1. At least annually, update the list of Components and Segments and/or description if any changes occur within the Segment.
2. Perform maintenance on the greater of 5% of the Components (addressed in the performance based PSMP) in each Segment or 3 individual Components within the Segment in each year.
3. For the prior year, analyze the maintenance program activities and results for each Segment to determine the overall performance of the Segment.
4. Using the prior year's data, determine the maximum allowable maintenance interval for each Segment such that the Segment experiences Countable Events on no more than 4% of the Components within the Segment, for the greater of either the last 30 Components maintained or all Components maintained in the previous year.

~~5.~~ If the Components in a Segment maintained through a performance-based PSMP experience 4% or more Countable Events, develop, document, and implement an action plan to reduce the Countable Events to less than 4% of the Segment population within 3 years.

Exhibit B

Implementation Plan

Implementation Plan

Protection System, Automatic Reclosing, and Sudden Pressure Relaying Maintenance
PRC-005-4

Standards Involved
Approval:

- PRC-005-4 – Protection System, Automatic Reclosing, and Sudden Pressure Relaying Maintenance

Retirement:

- PRC-005-3 – Protection System and Automatic Reclosing Maintenance

Prerequisite Approvals:
N/A

Background:
This implementation plan incorporates and carries forward any aspects of implementation plans for prior versions of PRC-005 where those standards are still in the implementation phase.

The Implementation Plan for PRC-005-4 addresses Sudden Pressure Relaying, Protection Systems as outlined in PRC-005-2, and Automatic Reclosing Components as outlined in PRC-005-3. PRC-005-4 establishes minimum maintenance activities for Sudden Pressure Relaying Component Types and the maximum allowable maintenance intervals for these maintenance activities. PRC-005-4 requires entities to revise the Protection System Maintenance Program by now including Sudden Pressure Relaying Components.

The Implementation Plan reflects consideration of the following:

1. The requirements set forth in the proposed standard, which carry forward requirements from PRC-005-2 and PRC-005-3, establish minimum maintenance activities for Protection System, Automatic Reclosing, and Sudden Pressure Relaying Component Types as well as the maximum allowable maintenance intervals for these maintenance activities. The maintenance activities established may not be presently performed by some entities and the established maximum allowable intervals may be shorter than those currently in use by some entities.
2. For entities not presently performing a maintenance activity or using longer intervals than the maximum allowable intervals established in the proposed standard, it is unrealistic for those entities to be immediately compliant with the new activities or intervals. Further, entities should be allowed to become compliant in such a way as to facilitate a continuing maintenance program.

3. Entities that have previously been performing maintenance within the newly specified intervals may not have all the documentation needed to demonstrate compliance with all of the maintenance activities specified.
4. The Implementation Schedule set forth below in this document carries forward the implementation schedules contained in PRC-005-2 and PRC-005-3 and includes changes needed to address the addition of Sudden Pressure Relaying Components in PRC-005-4.
5. The Implementation Schedule set forth in this document facilitates implementation of the more lengthy maintenance intervals within the revised Protection System Maintenance Program in approximately equally-distributed steps over those intervals prescribed for each respective maintenance activity in order that entities may implement this standard in a systematic method that facilitates an effective ongoing Protection System Maintenance Program.

General Considerations:

Each Transmission Owner, Generator Owner, and Distribution Provider shall maintain documentation to demonstrate compliance with PRC-005-1b, PRC-008-0, PRC-011-0, and PRC-017-0 until that entity meets the requirements of PRC-005-2, or the combined successor standards PRC-005-3 and PRC-005-4, in accordance with this implementation plan.

While entities are transitioning from PRC-005-1b, PRC-008-0, PRC-011-0, PRC-017-0, each entity must be prepared to identify:

- All of its applicable Protection System, Automatic Reclosing, and Sudden Pressure Relaying Components, and
- Whether a Component was last maintained according to PRC-005-1b, PRC-008-0, PRC-011-0, PRC-017-0, or a successor PRC-005 standard.

Effective Date

PRC-005-4 shall become effective on the first day of the first calendar quarter after the date that the standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first calendar quarter after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

Retirement of Existing Standards:

Standards PRC-005-1b, PRC-008-0, PRC-011-0, and PRC-017-0 shall remain active and applicable to an entity's Protection System maintenance activities not yet transitioned to PRC-005-2 or a successor standard during transition. Standards PRC-005-1b, PRC-008-0, PRC-011-0, and PRC-017-0 shall be retired at midnight of the day immediately prior to the first day of the first calendar quarter one hundred fifty-six (156) months following applicable regulatory approval of PRC-005-2 or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities; or, in those

jurisdictions where no regulatory approval is required, at midnight of the day immediately prior to the first day of the first calendar quarter one hundred sixty-eight (168) months following the November 2012 NERC Board of Trustees' adoption of PRC-005-2.

PRC-005-2 shall be retired at midnight of the day immediately prior to the first day of the first calendar quarter, twelve (12) calendar months following applicable regulatory approval of PRC-005-3, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities; or, in those jurisdictions where no regulatory approval is required, the first day of the first calendar quarter twelve (12) calendar months from the date of Board of Trustees' adoption.

PRC-005-3 shall be retired at midnight of the day immediately prior to the first day of the first calendar quarter following applicable regulatory approval of PRC-005-4, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities; or, in those jurisdictions where no regulatory approval is required, the first day of the first calendar quarter from the date of Board of Trustees' adoption.

Implementation Plan for Definitions:

This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the Reliability Standards Glossary of Terms (Glossary) are not repeated here. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, the Glossary definition will be removed from the individual standard and added to the Glossary. The definitions of terms used only in the standard will remain in the standard.

Glossary Definition:

Protection System Maintenance Program (PSMP) — An ongoing program by which Protection System, Automatic Reclosing, and Sudden Pressure Relaying Components are kept in working order and proper operation of malfunctioning Components is restored. A maintenance program for a specific Component includes one or more of the following activities:

- Verify — Determine that the Component is functioning correctly.
- Monitor — Observe the routine in-service operation of the Component.
- Test — Apply signals to a Component to observe functional performance or output behavior, or to diagnose problems.
- Inspect — Examine for signs of Component failure, reduced performance or degradation.
- Calibrate — Adjust the operating threshold or measurement accuracy of a measuring element to meet the intended performance requirement.

Definitions of Terms Used in the Standard:

Sudden Pressure Relaying – A system that trips an interrupting device(s) to isolate the equipment it is monitoring and includes the following Components:

- Fault pressure relay – a mechanical relay or device that detects rapid changes in gas pressure, oil pressure, or oil flow that are indicative of Faults within liquid-filled, wire-wound equipment
- Control circuitry associated with a fault pressure relay

Component Type –

- Any one of the five specific elements of a Protection System.
- Any one of the two specific elements of Automatic Reclosing.
- Any one of the two specific elements of Sudden Pressure Relaying.

Component – Any individual discrete piece of equipment included in a Protection System, Automatic Reclosing, or Sudden Pressure Relaying.

Countable Event – A failure of a Component requiring repair or replacement, any condition discovered during the maintenance activities in Tables 1-1 through 1-5, Table 3, Tables 4-1 through 4-2, and Table 5, which requires corrective action or a Protection System Misoperation attributed to hardware failure or calibration failure. Misoperations due to product design errors, software errors, relay settings different from specified settings, Protection System Component, Automatic Reclosing, or Sudden Pressure Relaying configuration or application errors are not included in Countable Events.

Implementation Plan for New or Revised Definitions:

New and revised definitions (Sudden Pressure Relaying, Protection System Maintenance Program, Component Type, Component, and Countable Event) shall become effective after the date that the definitions are approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a definition to go into effect. Where approval by an applicable governmental authority is not required, the definitions shall become effective on the first day of the first calendar quarter after the date the definitions are adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

Implementation Plan for Requirements R1, R2, and R5:

For Protection System Components, entities shall be 100% compliant on the first day of the first calendar quarter twelve (12) months following applicable regulatory approvals of PRC-005-2 or, in those jurisdictions where no regulatory approval is required, on the first day of the first calendar quarter twenty-four (24) months following the November 2012 NERC Board of Trustees' adoption of PRC-005-2 or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

For Automatic Reclosing Components, entities shall be 100% compliant on the first day of the first calendar quarter twelve (12) months following applicable regulatory approvals of PRC-005-3 or, in those jurisdictions where no regulatory approval is required, on the first day of the first calendar quarter twenty-four (24) months following NERC Board of Trustees' adoption of PRC-005-3 or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.
For Sudden Pressure Relaying Components, entities shall be 100% compliant on the first day of the first calendar quarter twelve (12) months following applicable regulatory approvals of PRC-005-4 or, in those jurisdictions where no regulatory approval is required, on the first day of the first calendar quarter twenty-four (24) months following NERC Board of Trustees' adoption of PRC-005-4 or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

Implementation Plan for Requirements R3 and R4:

1. For Protection System Component maintenance activities with maximum allowable intervals of less than one (1) calendar year, as established in Tables 1-1 through 1-5:

    - The entity shall be 100% compliant on the first day of the first calendar quarter eighteen (18) months following applicable regulatory approval of PRC-005-2, or in those jurisdictions where no regulatory approval is required, on the first day of the first calendar quarter thirty (30) months following the November 2012 NERC Board of Trustees' adoption of PRC-005-2 or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

2. For Protection System Component maintenance activities with maximum allowable intervals one (1) calendar year or more, but two (2) calendar years or less, as established in Tables 1-1 through 1-5:

    - The entity shall be 100% compliant on the first day of the first calendar quarter thirty-six (36) months following applicable regulatory approval of PRC-005-2 or, in those jurisdictions where no regulatory approval is required, on the first day of the first calendar quarter forty-eight (48) months following the November 2012 NERC Board of Trustees' adoption of PRC-005-2 or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

3. For Protection System Component maintenance activities with maximum allowable intervals of three (3) calendar years, as established in Tables 1-1 through 1-5:

    - The entity shall be at least 30% compliant on the first day of the first calendar quarter twenty-four (24) months following applicable regulatory approval of PRC-005-2 (or, for generating plants with scheduled outage intervals exceeding two years, at the conclusion of the first succeeding maintenance outage) or, in those jurisdictions where no regulatory approval is required, on the first day of the first calendar quarter thirty-six (36) months following the November 2012 NERC Board of Trustees' adoption of PRC-005-2 or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

- The entity shall be at least 60% compliant on the first day of the first calendar quarter thirty-six (36) months following applicable regulatory approval of PRC-005-2 or, in those jurisdictions where no regulatory approval is required, on the first day of the first calendar quarter forty-eight (48) months following NERC Board of Trustees' adoption of PRC-005-2 or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.
- The entity shall be 100% compliant on the first day of the first calendar quarter forty-eight (48) months following applicable regulatory approval of PRC-005-2 or, in those jurisdictions where no regulatory approval is required, on the first day of the first calendar quarter sixty (60) months following the November 2012 NERC Board of Trustees' adoption of PRC-005-2 or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

4. For Protection System Component maintenance activities with maximum allowable intervals of six (6) calendar years, as established in Tables 1-1 through 1-5 and Table 3:
    - The entity shall be at least 30% compliant on the first day of the first calendar quarter thirty-six (36) months following applicable regulatory approval of PRC-005-2 (or, for generating plants with scheduled outage intervals exceeding three years, at the conclusion of the first succeeding maintenance outage) or, in those jurisdictions where no regulatory approval is required, on the first day of the first calendar quarter forty-eight (48) months following the November 2012 NERC Board of Trustees' adoption of PRC-005-2 or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.
    - The entity shall be at least 60% compliant on the first day of the first calendar quarter sixty (60) months following applicable regulatory approval of PRC-005-2 or, in those jurisdictions where no regulatory approval is required, on the first day of the first calendar quarter seventy-two (72) months following the November 2012 NERC Board of Trustees' adoption of PRC-005-2 or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.
    - The entity shall be 100% compliant on the first day of the first calendar quarter eighty-four (84) months following applicable regulatory approval of PRC-005-2 or, in those jurisdictions where no regulatory approval is required, on the first day of the first calendar quarter ninety-six (96) months following the November 2012 NERC Board of Trustees' adoption of PRC-005-2 or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.
5. For Automatic Reclosing Component maintenance activities with maximum allowable intervals of six (6) calendar years, as established in Table 4-1, 4-2(a) and 4-2(b):
    - The entity shall be at least 30% compliant on the first day of the first calendar quarter thirty-six (36) months following applicable regulatory approval of PRC-005-3 (or, for generating plants with scheduled outage intervals exceeding three years, at the conclusion of the first succeeding maintenance outage) or, in those jurisdictions where no regulatory approval is required, on the

first day of the first calendar quarter forty-eight (48) months following NERC Board of Trustees' adoption of PRC-005-3 or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

- The entity shall be at least 60% compliant on the first day of the first calendar quarter sixty (60) months following applicable regulatory approval of PRC-005-3 or, in those jurisdictions where no regulatory approval is required, on the first day of the first calendar quarter seventy-two (72) months following NERC Board of Trustees' adoption of PRC-005-3, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.
- The entity shall be 100% compliant on the first day of the first calendar quarter eighty-four (84) months following applicable regulatory approval of PRC-005-3 or, in those jurisdictions where no regulatory approval is required, on the first day of the first calendar quarter ninety-six (96) months following NERC Board of Trustees' adoption of PRC-005-3 or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

6. For Sudden Pressure Relaying Component maintenance activities with maximum allowable intervals of six (6) calendar years, as established in Table 5:

    - The entity shall be at least 30% compliant on the first day of the first calendar quarter thirty-six (36) months following applicable regulatory approval of PRC-005-4 (or, for generating plants with scheduled outage intervals exceeding three years, at the conclusion of the first succeeding maintenance outage) or, in those jurisdictions where no regulatory approval is required, on the first day of the first calendar quarter forty-eight (48) months following NERC Board of Trustees' adoption of PRC-005-4 or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.
    - The entity shall be at least 60% compliant on the first day of the first calendar quarter sixty (60) months following applicable regulatory approval of PRC-005-4 or, in those jurisdictions where no regulatory approval is required, on the first day of the first calendar quarter seventy-two (72) months following NERC Board of Trustees' adoption of PRC-005-4, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.
    - The entity shall be 100% compliant on the first day of the first calendar quarter eighty-four (84) months following applicable regulatory approval of PRC-005-4 or, in those jurisdictions where no regulatory approval is required, on the first day of the first calendar quarter ninety-six (96) months following NERC Board of Trustees' adoption of PRC-005-4 or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

7. For Protection System Component maintenance activities with maximum allowable intervals of twelve (12) calendar years, as established in Tables 1-1 through 1-5, Table 2, and Table 3:

    - The entity shall be at least 30% compliant on the first day of the first calendar quarter sixty (60) months following applicable regulatory approval of PRC-005-2 or, in those jurisdictions where no regulatory approval is required, on the first day of the first calendar quarter seventy-two

(72) months following the November 2012 NERC Board of Trustees' adoption of PRC-005-2 or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

- The entity shall be at least 60% compliant on the first day of the first calendar quarter following one hundred eight (108) months following applicable regulatory approval of PRC-005-2 or, in those jurisdictions where no regulatory approval is required, on the first day of the first calendar quarter one hundred twenty (120) months following the November 2012 NERC Board of Trustees' adoption of PRC-005-2 or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.
- The entity shall be 100% compliant on the first day of the first calendar quarter one hundred fifty-six (156) months following applicable regulatory approval of PRC-005-2 or, in those jurisdictions where no regulatory approval is required, on the first day of the first calendar quarter one hundred sixty-eight (168) months following the November 2012 NERC Board of Trustees' adoption of PRC-005-2 or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

8. For Automatic Reclosing Component maintenance activities with maximum allowable intervals of twelve (12) calendar years, as established in Table 4-1, 4-2(a) and 4-2(b):

   - The entity shall be at least 30% compliant on the first day of the first calendar quarter sixty (60) months following applicable regulatory approval of PRC-005-3 or, in those jurisdictions where no regulatory approval is required, on the first day of the first calendar quarter seventy-two (72) months following NERC Board of Trustees' adoption of PRC-005-3 or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.
   - The entity shall be at least 60% compliant on the first day of the first calendar quarter following one hundred eight (108) months following applicable regulatory approval of PRC-005-3 or, in those jurisdictions where no regulatory approval is required, on the first day of the first calendar quarter one hundred twenty (120) months following NERC Board of Trustees' adoption of PRC-005-3 or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.
   - The entity shall be 100% compliant on the first day of the first calendar quarter one hundred fifty-six (156) months following applicable regulatory approval of PRC-005-3 or, in those jurisdictions where no regulatory approval is required, on the first day of the first calendar quarter one hundred sixty-eight (168) months following NERC Board of Trustees' adoption of PRC-005-3 or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

9. For Sudden Pressure Relaying Component maintenance activities with maximum allowable intervals of twelve (12) calendar years, as established in Table 5:

- The entity shall be at least 30% compliant on the first day of the first calendar quarter sixty (60) months following applicable regulatory approval of PRC-005-4 or, in those jurisdictions where no regulatory approval is required, on the first day of the first calendar quarter seventy-two (72) months following NERC Board of Trustees' adoption of PRC-005-4 or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.
- The entity shall be at least 60% compliant on the first day of the first calendar quarter following one hundred eight (108) months following applicable regulatory approval of PRC-005-4 or, in those jurisdictions where no regulatory approval is required, on the first day of the first calendar quarter one hundred twenty (120) months following NERC Board of Trustees' adoption of PRC-005-4 or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.
- The entity shall be 100% compliant on the first day of the first calendar quarter one hundred fifty-six (156) months following applicable regulatory approval of PRC-005-4 or, in those jurisdictions where no regulatory approval is required, on the first day of the first calendar quarter one hundred sixty-eight (168) months following NERC Board of Trustees' adoption of PRC-005-4 or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

Applicability:

This standard applies to the following functional entities:

- Transmission Owner
- Generator Owner
- Distribution Provider

Exhibit C

Order No. 672 Criteria

Exhibit C — Order No. 672 Criteria — Proposed Reliability Standard PRC-005-4

Order No. 672 Criteria

In Order No. 672,[1] the Commission identified a number of criteria it will use to analyze Reliability Standards proposed for approval to ensure they are just, reasonable, not unduly discriminatory or preferential, and in the public interest. The discussion below identifies these factors and explains how the proposed Reliability Standard has met or exceeded the criteria:

1. **Proposed Reliability Standards must be designed to achieve a specified reliability goal and must contain a technically sound means to achieve that goal.[2]**

The purpose of proposed Reliability Standard PRC-005-4 is to document and implement programs for the maintenance of all Protection Systems, Automatic Reclosing, and Sudden Pressure Relaying affecting the reliability of the Bulk Electric System so that they are kept in working order. The revised Reliability Standard requires that entities develop an appropriate Protection System Maintenance Program, that they implement their program, and that, in the event they are unable to restore Sudden Pressure Relaying Components to proper working order while performing maintenance, they initiate the follow-up activities necessary to resolve those

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[1] *Rules Concerning Certification of the Electric Reliability Organization; and Procedures for the Establishment, Approval, and Enforcement of Electric Reliability Standards*, Order No. 672, FERC Stats. & Regs. ¶ 31,204, *order on reh'g*, Order No. 672-A, FERC Stats. & Regs. ¶ 31,212 (2006).

[2] Order No. 672 at P 321. The proposed Reliability Standard must address a reliability concern that falls within the requirements of section 215 of the FPA. That is, it must provide for the reliable operation of Bulk-Power System facilities. It may not extend beyond reliable operation of such facilities or apply to other facilities. Such facilities include all those necessary for operating an interconnected electric energy transmission network, or any portion of that network, including control systems. The proposed Reliability Standard may apply to any design of planned additions or modifications of such facilities that is necessary to provide for reliable operation. It may also apply to Cybersecurity protection.

Order No. 672 at P 324. The proposed Reliability Standard must be designed to achieve a specified reliability goal and must contain a technically sound means to achieve this goal. Although any person may propose a topic for a Reliability Standard to the ERO, in the ERO's process, the specific proposed Reliability Standard should be developed initially by persons within the electric power industry and community with a high level of technical expertise and be based on sound technical and engineering criteria. It should be based on actual data and lessons learned from past operating incidents, where appropriate. The process for ERO approval of a proposed Reliability Standard should be fair and open to all interested persons.

maintenance issues. Proposed PRC-005-4 adds detailed tables of minimum maintenance activities and maximum maintenance intervals for Sudden Pressure Relaying to PRC-005-2 and to the proposed PRC-005-3 Reliability Standards, extending the benefits of a strong maintenance program to these Components. The Sudden Pressure Relaying devices included in the proposed PRC-005-4 are based on the findings of the SPCS Report and Supplemental Report included as **Exhibit D and E**. The proposed Reliability Standard is also designed to fulfill the Commission's concern in Order No. 758 regarding the addition of certain devices that respond to non-electrical quantities to the requirements of PRC-005 Reliability Standard.

2. Proposed Reliability Standards must be applicable only to users, owners and operators of the bulk power system, and must be clear and unambiguous as to what is required and who is required to comply.[3]

The proposed Reliability Standard is clear and unambiguous as to what is required and who is required to comply, in accordance with Order No. 672. Aside from minor modifications to facilitate coverage of Sudden Pressure Relaying in the Reliability Standard, the Requirements previously-approved by the Commission in PRC-005-2, and the Requirements in PRC-005-3 currently under review by the Commission, are unchanged. The proposed Reliability Standard applies to Generator Owners, Transmission Owners, and Distribution Providers and clearly articulates the actions that each entity must take to comply with the proposed Reliability Standard.

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[3] Order No. 672 at P 322. The proposed Reliability Standard may impose a requirement on any user, owner, or operator of such facilities, but not on others.

Order No. 672 at P 325. The proposed Reliability Standard should be clear and unambiguous regarding what is required and who is required to comply. Users, owners, and operators of the Bulk-Power System must know what they are required to do to maintain reliability.

3. A proposed Reliability Standard must include clear and understandable consequences and a range of penalties (monetary and/or non-monetary) for a violation.[4]

Because the Requirements contained in proposed Reliability Standard PRC-005-4 have not changed compared to those contained in the Commission-approved Reliability Standard PRC-005-2 and in the proposed PRC-005-3, the Standard Drafting Team determined that no revisions were necessary to the VRFs for the proposed Reliability Standard. NERC, therefore, requests that the Commission approve the VRFs as applied to the additional Sudden Pressure Relaying Components now included in the proposed Reliability Standard.

The VSLs in PRC-005-2 and PRC-005-3 have been revised accordingly to add the additional Component into the levels of severity. The changes are consistent with the approach taken for the VSLs in the previous versions of Reliability Standard PRC-005.

4. A proposed Reliability Standard must identify clear and objective criterion or measure for compliance, so that it can be enforced in a consistent and non-preferential manner.[5]

The proposed Reliability Standard continues to include Measures that support the Requirements by clearly identifying what is required and how the Requirement will be enforced. The Measures have been slightly modified to include Sudden Pressure Relaying references where necessary. The proposed Measures are as follows:

> **M1.** Each Transmission Owner, Generator Owner and Distribution Provider shall have a documented Protection System Maintenance Program in accordance with Requirement R1.
>
> For each Protection System, Automatic Reclosing, and Sudden Pressure Relaying Component Type, the documentation shall include the type of maintenance method applied (time-based, performance-based, or a combination of these maintenance methods), and shall include all

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4 Order No. 672 at P 326. The possible consequences, including range of possible penalties, for violating a proposed Reliability Standard should be clear and understandable by those who must comply.

5 Order No. 672 at P 327. There should be a clear criterion or measure of whether an entity is in compliance with a proposed Reliability Standard. It should contain or be accompanied by an objective measure of compliance so that it can be enforced and so that enforcement can be applied in a consistent and non-preferential manner.

batteries associated with the station dc supply Component Types in a time-based program as described in Table 1-4 and Table 3. (Part 1.1)

For Component Types that use monitoring to extend the maintenance intervals, the responsible entity(s) shall have evidence for each Protection System, Automatic Reclosing, and Sudden Pressure Relaying Component Type (such as manufacturer's specifications or engineering drawings) of the appropriate monitored Component attributes as specified in Tables 1-1 through 1-5, Table 2, Table 3, Table 4-1 through 4-2, and Table 5. (Part 1.2)

M2. Each Transmission Owner, Generator Owner, and Distribution Provider that uses performance-based maintenance intervals shall have evidence that its current performance-based maintenance program(s) is in accordance with Requirement R2, which may include, but is not limited to, Component lists, dated maintenance records, and dated analysis records and results.

M3. Each Transmission Owner, Generator Owner, and Distribution Provider that utilizes time-based maintenance program(s) shall have evidence that it has maintained its Protection System, Automatic Reclosing, and Sudden Pressure Relaying Components included within its time-based program in accordance with Requirement R3. The evidence may include, but is not limited to, dated maintenance records, dated maintenance summaries, dated check-off lists, dated inspection records, or dated work orders.

M4. Each Transmission Owner, Generator Owner, and Distribution Provider that utilizes performance-based maintenance intervals in accordance with Requirement R2 shall have evidence that it has implemented the Protection System Maintenance Program for the Protection System, Automatic Reclosing, and Sudden Pressure Relaying Components included in its performance-based program in accordance with Requirement R4. The evidence may include, but is not limited to, dated maintenance records, dated maintenance summaries, dated check-off lists, dated inspection records, or dated work orders.

M5. Each Transmission Owner, Generator Owner, and Distribution Provider shall have evidence that it has undertaken efforts to correct identified Unresolved Maintenance

Issues in accordance with Requirement R5. The evidence may include, but is not limited to, work orders, replacement Component orders, invoices, project schedules with completed milestones, return material authorizations (RMAs) or purchase orders.

These Measures provide clarity regarding how the Requirements will be enforced, and help ensure that the Requirements will be enforced in a clear, consistent, and non-preferential manner and without prejudice to any party.

5. **Proposed Reliability Standards should achieve a reliability goal effectively and efficiently — but do not necessarily have to reflect "best practices" without regard to implementation cost or historical regional infrastructure design.**[6]

The proposed Reliability Standard achieves its reliability goals effectively and efficiently in accordance with Order No. 672. The proposed Reliability Standard includes certain Sudden Pressure Relaying devices as explained in the Petition and reflected in the Applicability section of the proposed Reliability Standard. NERC engaged the System Protection and Control Subcommittee ("SPCS"), a subcommittee of the NERC Planning Committee, to support the Project 2007-17-3 Standard Drafting Team assigned to modify PRC-005-3. The SPCS Report and Supplemental Report (**Exhibit D and E**) recommend including sudden pressure relays that are utilized in a trip application and may affect the Reliable Operation of the Bulk-Power System within the scope of PRC-005. These specific sudden pressure relays have been included in the Applicability section of PRC-005-3 to address Order No. 758. By engaging the NERC technical subcommittee of the Planning Committee in the analysis to determine which specific sudden pressure relays should be included, the proposed Reliability Standard does not over-include devices that do not affect reliability. Engaging the technical committee in this analysis assisted the Standard Drafting Team in reaching the most efficient and effective determination regarding the Applicability inclusions in the proposed Reliability Standard.

6. **Proposed Reliability Standards cannot be "lowest common denominator,"** ***i.e.,*** **cannot reflect a compromise that does not adequately protect Bulk-Power System**

[6] Order No. 672 at P 328. The proposed Reliability Standard does not necessarily have to reflect the optimal method, or "best practice," for achieving its reliability goal without regard to implementation cost or historical regional infrastructure design. It should however achieve its reliability goal effectively and efficiently.

reliability. Proposed Reliability Standards can consider costs to implement for smaller entities, but not at consequences of less than excellence in operating system reliability.[7]

The proposed Reliability Standard does not reflect a "lowest common denominator" approach. In addition to satisfying a Commission reliability concerns, the revisions contained in the proposed Reliability Standard require expanded application of maintenance plans and processes, helping to preserve reliability by addressing potential issues before they impact reliability. The Sudden Pressure Relaying devices included in the proposed Reliability Standard also reflect the detailed studies by NERC's technical subcommittee, as noted above and in the Petition. NERC staff also conducted an informal industry survey to develop recommendations for minimum maintenance activities and maximum maintenance intervals associated with Sudden Pressure Relaying. Lastly, to validate the information collected from the survey, the SPCS contacted several industry organizations, which indicated the results of the SPCS industry survey were consistent with their respective experiences.

7. **Proposed Reliability Standards must be designed to apply throughout North America to the maximum extent achievable with a single Reliability Standard while not favoring one geographic area or regional model. It should take into account regional variations in the organization and corporate structures of transmission owners and operators, variations in generation fuel type and ownership patterns, and regional variations in market design if these affect the proposed Reliability Standard.**[8]

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[7] Order No. 672 at P 329. The proposed Reliability Standard must not simply reflect a compromise in the ERO's Reliability Standard development process based on the least effective North American practice — the so-called "lowest common denominator" — if such practice does not adequately protect Bulk-Power System reliability. Although FERC will give due weight to the technical expertise of the ERO, we will not hesitate to remand a proposed Reliability Standard if we are convinced it is not adequate to protect reliability.

Order No. 672 at P 330. A proposed Reliability Standard may take into account the size of the entity that must comply with the Reliability Standard and the cost to those entities of implementing the proposed Reliability Standard. However, the ERO should not propose a "lowest common denominator" Reliability Standard that would achieve less than excellence in operating system reliability solely to protect against reasonable expenses for supporting this vital national infrastructure. For example, a small owner or operator of the Bulk-Power System must bear the cost of complying with each Reliability Standard that applies to it.

[8] Order No. 672 at P 331. A proposed Reliability Standard should be designed to apply throughout the interconnected North American Bulk-Power System, to the maximum extent this is achievable with a single Reliability Standard. The proposed Reliability Standard should not be based on a single geographic or regional

The proposed Reliability Standard applies throughout North America and does not favor one geographic area or regional model.

8. Proposed Reliability Standards should cause no undue negative effect on competition or restriction of the grid beyond any restriction necessary for reliability.[9]

Proposed Reliability Standard PRC-005-4 has no undue negative effect on competition. The proposed Reliability Standard requires the same performance by each of the applicable Functional Entities—Generator Owners, Transmission Owners, and Distribution Providers—in requiring the development of maintenance plans for Sudden Pressure Relaying.

The proposed Reliability Standard does not unreasonably restrict the available generation or transmission capability or limit use of the Bulk-Power System in a preferential manner.

9. The implementation time for the proposed Reliability Standard is reasonable.[10]

The proposed effective dates for the proposed Reliability Standard are just and reasonable and appropriately balance the urgency in the need to implement the proposed Reliability Standard against the reasonableness of the time allowed for those who must comply to develop necessary procedures, software, facilities, staffing or other relevant capability. This will allow applicable entities adequate time to ensure compliance with the Requirements. The proposed

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model but should take into account geographic variations in grid characteristics, terrain, weather, and other such factors; it should also take into account regional variations in the organizational and corporate structures of transmission owners and operators, variations in generation fuel type and ownership patterns, and regional variations in market design if these affect the proposed Reliability Standard.

9 Order No. 672 at P 332. As directed by section 215 of the FPA, FERC itself will give special attention to the effect of a proposed Reliability Standard on competition. The ERO should attempt to develop a proposed Reliability Standard that has no undue negative effect on competition. Among other possible considerations, a proposed Reliability Standard should not unreasonably restrict available transmission capability on the Bulk-Power System beyond any restriction necessary for reliability and should not limit use of the Bulk-Power System in an unduly preferential manner. It should not create an undue advantage for one competitor over another.

10 Order No. 672 at P 333. In considering whether a proposed Reliability Standard is just and reasonable, FERC will consider also the timetable for implementation of the new requirements, including how the proposal balances any urgency in the need to implement it against the reasonableness of the time allowed for those who must comply to develop the necessary procedures, software, facilities, staffing or other relevant capability.

effective dates are explained in the proposed Implementation Plan, attached as **Exhibit B**. Except for the addition of certain Sudden Pressure Relaying devices, the Implementation Plan remains unchanged from the prior versions of this Reliability Standard. The same timeframes for compliance with the Requirements will apply counting forward from the effective date of an order approving proposed PRC-005-4.

10. The Reliability Standard was developed in an open and fair manner and in accordance with the Commission-approved Reliability Standard development process.[11]

The proposed Reliability Standard was developed in accordance with NERC's Commission-approved, ANSI-accredited processes for developing and approving Reliability Standards. **Exhibit H** includes a summary of the Reliability Standard development proceedings, and details the processes followed to develop the proposed Reliability Standard.

These processes included, among other things, multiple comment periods, pre-ballot review periods, and balloting periods. Additionally, all meetings of the Standard Drafting Team were properly noticed and open to the public. The initial and recirculation ballots both achieved a quorum and exceeded the required ballot pool approval levels.

11. NERC must explain any balancing of vital public interests in the development of proposed Reliability Standards.[12]

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[11] Order No. 672 at P 334. Further, in considering whether a proposed Reliability Standard meets the legal standard of review, we will entertain comments about whether the ERO implemented its Commission-approved Reliability Standard development process for the development of the particular proposed Reliability Standard in a proper manner, especially whether the process was open and fair. However, we caution that we will not be sympathetic to arguments by interested parties that choose, for whatever reason, not to participate in the ERO's Reliability Standard development process if it is conducted in good faith in accordance with the procedures approved by FERC.

[12] Order No. 672 at P 335. Finally, we understand that at times development of a proposed Reliability Standard may require that a particular reliability goal must be balanced against other vital public interests, such as environmental, social and other goals. We expect the ERO to explain any such balancing in its application for approval of a proposed Reliability Standard.

NERC has identified no competing public interests regarding the request for approval of the proposed Reliability Standard. No comments were received indicating the proposed Reliability Standard is in conflict with other vital public interests.

12. Proposed Reliability Standards must consider any other appropriate factors.[13]

No other factors relevant to whether the proposed Reliability Standard is just and reasonable were identified.

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[13] Order No. 672 at P 323. In considering whether a proposed Reliability Standard is just and reasonable, we will consider the following general factors, as well as other factors that are appropriate for the particular Reliability Standard proposed.

Exhibit D

SPCS Report: ***Sudden Pressure Relays and Other Devices that Respond to Non-Electrical Quantities***

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Sudden Pressure Relays and Other Devices that Respond to Non-Electrical Quantities

SPCS Input for Standard Development in Response to FERC Order No. 758

System Protection and Control Subcommittee

December 2013

RELIABILITY | ACCOUNTABILITY

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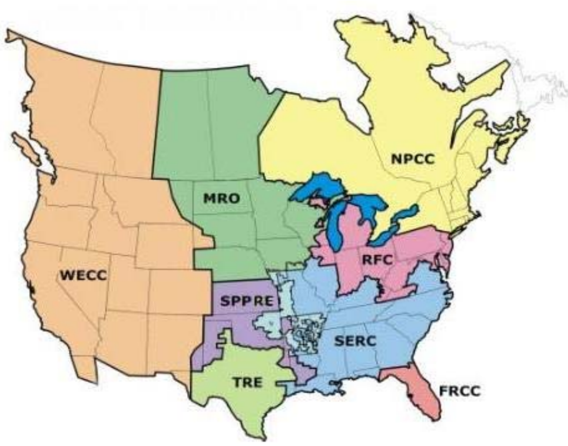
NERC's Mission

The North American Electric Reliability Corporation (NERC) is an international regulatory authority established to enhance the reliability of the Bulk-Power System in North America. NERC develops and enforces Reliability Standards; assesses adequacy annually via a ten-year forecast and winter and summer forecasts; monitors the Bulk-Power System; and educates, trains, and certifies industry personnel. NERC is the electric reliability organization for North America, subject to oversight by the U.S. Federal Energy Regulatory Commission (FERC) and governmental authorities in Canada.[1]

NERC assesses and reports on the reliability and adequacy of the North American Bulk-Power System, which is divided into eight Regional areas, as shown on the map and table below. The users, owners, and operators of the Bulk-Power System within these areas account for virtually all the electricity supplied in the U.S., Canada, and a portion of Baja California Norte, México.



Note: The highlighted area between SPP RE and SERC denotes overlapping Regional area boundaries. For example, some load serving entities participate in one Region and their associated transmission owner/operators in another.

NERC Regional Entities	
FRCC Florida Reliability Coordinating Council	**SERC** SERC Reliability Corporation
MRO Midwest Reliability Organization	**SPP RE** Southwest Power Pool Regional Entity
NPCC Northeast Power Coordinating Council	**TRE** Texas Reliability Entity
RFC ReliabilityFirst Corporation	**WECC** Western Electricity Coordinating Council

[1] As of June 18, 2007, the U.S. Federal Energy Regulatory Commission (FERC) granted NERC the legal authority to enforce Reliability Standards with all U.S. users, owners, and operators of the bulk power system, and made compliance with those standards mandatory and enforceable. In Canada, NERC presently has memorandums of understanding in place with provincial authorities in Ontario, New Brunswick, Nova Scotia, Québec, and Saskatchewan, and with the Canadian National Energy Board. NERC standards are mandatory and enforceable in Ontario and New Brunswick as a matter of provincial law. NERC has an agreement with Manitoba Hydro making reliability standards mandatory for that entity, and Manitoba has recently adopted legislation setting out a framework for standards to become mandatory for users, owners, and operators in the province. In addition, NERC has been designated as the "electric reliability organization" under Alberta's Transportation Regulation, and certain reliability standards have been approved in that jurisdiction; others are pending. NERC and NPCC have been recognized as standards-setting bodies by the Régie de l'énergie of Québec, and Québec has the framework in place for reliability standards to become mandatory. NERC's reliability standards are also mandatory in Nova Scotia and British Columbia. NERC is working with the other governmental authorities in Canada to achieve equivalent recognition.

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This technical document was approved by the NERC Planning Committee on December 11, 2013.

Executive Summary

In Order No. 758, FERC directed NERC to identify ". . . devices that are designed to sense or take action against any abnormal system condition that will affect reliable operation [of the Bulk-Power System]." In response to this directive, the Standards Committee requested the SPCS develop a technical report to support development of modifications to NERC Reliability Standard PRC-005, Protection System Maintenance and Testing. This report to the NERC Planning Committee (PC) addresses issues raised in the order regarding devices that respond to non-electrical quantities in general, and specifically sudden pressure relays. Upon PC approval, this report will be forwarded to the NERC Standards Committee to support a standard drafting team that will modify the existing standard or develop a new standard.

In developing this report, the SPCS evaluated all devices on the IEEE list of device numbers to identify which devices that respond to non-electrical quantities may impact reliable operation of the Bulk-Power System. As a result of this analysis, the SPCS concludes the only devices responding to non-electrical quantities that should be included in the applicability of PRC-005 are sudden pressure relays utilized in a tripping function. When applied in a tripping function, these devices initiate actions to clear faults to support reliable operation of the Bulk-Power System. The other devices evaluated respond to abnormal equipment conditions and take action to protect equipment from mechanical or thermal damage, or premature loss of life, rather than for the purpose of initiating fault clearing or mitigating an abnormal system condition to support reliable operation of the Bulk-Power System.

Based on its conclusion, the SPCS assessed existing industry practices for maintenance and testing of sudden pressure relays and conducted an informal industry survey to develop recommendations for maintenance and testing requirements to be included in PRC-005. To validate its approach, the SPCS contacted the following entities for their feedback: the IEEE Power System Relaying Committee, the NATF System Protection Practices Group, and the EPRI Generator Owner/Operator Technical Focus Group. All three of these organizations indicated the results of the SPCS survey are consistent with their respective experiences.

Considering its analysis and conclusion, the SPCS recommends the following guidance for future development of NERC Reliability Standard PRC-005, Protection System Maintenance, to address the concerns stated in FERC Order No. 758.

Modify PRC-005 to explicitly address maintenance and testing of the actuator device of the sudden pressure relay when applied as a protective device that trips a facility described in the applicability section of the Reliability Standard.

- Develop minimum maintenance activities for sudden pressure relays similar to Table 1-1: Protective Relay. Based on the survey results, the SPCS recommends the maximum interval for time-based maintenance programs be 6 years.
- Modify Table 1-5: Control Circuitry Associated With Protective Functions to explicitly include the sudden pressure control circuitry.

Introduction

Overview

In Order No. 758, FERC directed NERC to identify ". . . devices that are designed to sense or take action against any abnormal system condition that will affect reliable operation [of the Bulk-Power System]." In response to this directive, the Standards Committee requested the SPCS develop a technical report to support development of modifications to NERC Reliability Standard PRC-005, Protection System Maintenance and Testing. This report to the NERC Planning Committee (PC) addresses issues raised in the order regarding devices that respond to non-electrical quantities in general, and specifically sudden pressure relays.[2] Upon PC approval, this report will be forwarded to the NERC Standards Committee to support a standard drafting team that will modify the existing standard or develop a new standard.

Background

FERC Order No. 758 is associated with an interpretation of NERC Reliability Standard PRC-005-1, Protection System Maintenance and Testing. The interpretation addressed a series of questions submitted by the Regional Entities Compliance Monitoring Processes Working Group. The questions sought interpretation of whether specific components must be included in a maintenance and testing program. Specifically, the questions pertained to battery chargers, auxiliary relays and sensing devices, reclosing relays, dc circuitry, and communications systems.

In the order, FERC approved the interpretation as it pertains to the text of the existing standard and relevant defined terms in the NERC glossary. However, FERC identified concerns with certain devices that may impact reliability of the Bulk-Power System and directed that NERC address these concerns as specified in the order. The concerns specified in the order pertain to reclosing relays and to sudden pressure relays and other devices that respond to non-electrical quantities. Concerns related to maintenance and testing of reclosing relays are addressed in a separate, joint report of the NERC System Analysis and Modeling Subcommittee (SAMS) and the SPCS. This report focuses on the directive in the order pertaining to sudden pressure relays and other devices that respond to non-electrical quantities.

In the Notice of Proposed Rulemaking (NOPR) associated with this interpretation, FERC noted a concern that the proposed interpretation may not include all components that serve in some protective capacity. FERC further noted its concerns included the exclusion of auxiliary and non-electrical sensing relays. FERC proposed to direct NERC to develop a modification to Reliability Standard PRC-005-1 to include any component or device that is designed to detect defective lines or apparatuses or other power system conditions of an abnormal or dangerous nature, including devices designed to sense or take action against any abnormal system condition that will affect reliable operation, and to initiate appropriate control circuit actions.

In its comments on the NOPR, NERC noted that the revised definition of protection system and changes to PRC-005-1, in progress at that time, address FERC's concerns pertaining to auxiliary relays.[3] NERC also acknowledged FERC concerns related to protective relays that do not respond to electrical quantities and agreed that sudden pressure relays which trip for fault conditions should be maintained in accordance with NERC Reliability Standard requirements. However, NERC noted concern that the scope of the proposed directive was so broad that any device that is installed on the Bulk-Power System to monitor conditions in any fashion may be included. NERC further noted that, in fact, many of these devices are advisory in nature and should not be reflected within NERC standards if they do not serve a necessary reliability purpose.

NERC therefore proposed to develop, either independently or in association with other technical organizations such as IEEE, one or more technical documents which:

i. describe the devices and functions (to include sudden pressure relays which trip for fault conditions) that should address FERC's concern; and

ii. propose minimum maintenance activities for such devices and maximum maintenance intervals, including the technical basis for each.

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[2] Order No. 758 used the term sudden pressure relays, which the SPCS has interpreted to refer to the general class of relays responding to pressure, including sudden pressure, rapid pressure rise, and Buchholz relays.

[3] The changes referenced by NERC are included in PRC-005-2, adopted by the NERC Board of Trustees on November 7, 2012 and filed with a petition to FERC on February 26, 2013.

NERC stated that these technical documents will address those protective relays that are necessary for the reliable operation of the Bulk-Power System and will allow for differentiation between protective relays that detect faults from other devices that monitor the health of the individual equipment and are advisory in nature (e.g., oil temperature). Following development of the above-referenced document(s), NERC will propose a new or revised standard (e.g., PRC-005) using the NERC Reliability Standards development process to include maintenance of such devices, including establishment of minimum maintenance activities and maximum maintenance intervals.

In Order No. 758, FERC accepted the NERC proposal, and directed NERC to file, within sixty days of publication of the Final Rule, a schedule for informational purposes regarding the development of the technical documents referenced above, including the identification of devices that are designed to sense or take action against any abnormal system condition that will affect reliable operation. The SPCS has previously provided information regarding the schedule and steps planned to develop the proposed documents and this information was included in an informational filing on April 12, 2012 (see Appendix A). In accordance with the filed schedule, this report is submitted for approval to the Planning Committee to support standard development beginning in the first quarter of 2014.

Chapter 1 – Devices that Respond to Non-Electrical Quantities

Considerations for Inclusion in PRC-005

The SPCS considered the risk to reliable operation of the Bulk-Power System when developing a basis for identifying devices that should be included in the maintenance and testing standard. The following criteria were evaluated:

- Action taken: The SPCS considered the criticality of the effect of the action taken on system reliability, noting that tripping equipment is typically initiated when such action is necessary for reliability, although differentiation is necessary between tripping equipment to support reliable operation of the Bulk-Power System versus tripping to minimize the impact of abnormal operating conditions on a specific element. The SPCS also noted that initiating an alarm implies there is time for operator intervention to alleviate an adverse impact, and that initiating a control action implies immediate isolation of equipment (i.e., tripping) is not necessary.
- The risk associated with misoperation for an inadvertent operation or a failure to operate: The SPCS concluded that evaluating the impact on system reliability must consider the impact of both a failure of the device to operate when its operation is required (a dependability-related failure) and an inadvertent operation (a security-related failure).
- The risk of inadvertent operation during a disturbance: The SPCS considered the risk of a device inadvertently operating in response to a system disturbance and causing or contributing to a cascading event. Devices that respond to quantities directly associated with an abnormal condition are typically more secure than devices that monitor quantities indirectly associated with the abnormal condition. Furthermore, devices that respond to quantities associated with an abnormal equipment condition are typically unaffected by conditions experienced during system disturbances, and thus, are much less prone to inadvertent operation during a disturbance than relays that respond to electrical quantities.

Basis for Evaluation

The SPCS considered the above alternatives and identified the attributes important to assessing the potential for a device to affect reliability of the Bulk-Power System. After consideration of the attributes identified, the SPCS determined the best approach for performing an assessment was to group all device types into one of three categories to differentiate the risk to reliable operation of the Bulk-Power System. The three categories are listed in order of decreasing potential for risk to Bulk-Power System reliability. Of these, the first category is deemed to present a risk to Bulk-Power System reliability that is sufficient to include maintenance and testing of the device in PRC-005.

(1) Devices that initiate actions to clear faults or mitigate abnormal system conditions to support reliable operation of the Bulk-Power System,

(2) Devices that initiate action for abnormal equipment conditions for purposes other than supporting reliable operation of the Bulk-Power System, and

(3) Devices that monitor the health of the individual equipment and provide information that is advisory in nature.

Analysis of Individual Devices

The SPCS used the list of IEEE device numbers as a starting point for its assessment to assure that all possible devices responding to non-electrical quantities were considered. A list of all IEEE device numbers, including a description of each device is included in Appendix B.

To address the concern identified in Order No. 758, the SPCS used a two-step process to identify devices that initiate actions to clear faults or mitigate abnormal system conditions to support reliable operation of the Bulk-Power System.

In the first step, the SPCS identified devices already addressed as a result of the revised definition of Protection System or that are clearly not protective devices, such as primary equipment and control devices. The initial categorization of devices from this first step is documented in Appendix C. The SPCS used the following criteria to eliminate such devices and develop a short list of devices requiring detailed analysis.

- Protective relay already addressed in PRC-005-2: Maintenance and testing requirements are already established for these devices and no further consideration is required.
- Auxiliary relay already addressed in PRC-005-2: Maintenance and testing requirements are already established for these devices and no further consideration is required.
- Autoreclosing and synchronism check relays: Maintenance and testing considerations for these devices are proposed in a separate report to address the directive in paragraph 27 of Order No. 758[4]; these devices do not require further consideration in this report.
- Primary equipment: Devices such as governors, valves, motors, and circuit breakers are primary equipment, rather than protective devices, and do not require further consideration.
- Control device: Devices such as position switches, contactors, and field application relays that are used for starting, stopping, or otherwise controlling operation of equipment, respond to manual input or signals directly associated with operation of the equipment. These devices may be separate from, or an integral part of, the controlled equipment. Control systems are excluded from maintenance and testing requirements in PRC-005.

In the second step, the SPCS evaluated each device on the short list to group them into one of the three categories. The short list of devices and the SPCS evaluation of each device are included in Appendix D. The list includes a description of each device, whether the device trips a power system element and, if so, the potential risk to the Bulk-Power System based on the preceding criteria. Classification of devices on the short list is presented in Table 1. Some devices appear in more than one category; e.g., some devices may be used to alarm or to isolate equipment, depending on the application and the practices that entities have developed specific to their circumstances.

As a result of the analysis, the SPCS concludes that sudden pressure relays that are utilized in a trip application should be included in the Protection System Maintenance and Testing standard. Recommendations for minimum maintenance activities and maximum intervals are discussed in the next section of this report.

[4] The SPCS recommended modifications to PRC-005 to explicitly address maintenance and testing of autoreclosing relays applied as an integral part of a SPS, and autoreclosing relays at or in proximity to certain generating plants. See *Considerations for Maintenance and Testing of Autoreclosing Schemes*, NERC System Analysis and Modeling Subcommittee and System Protection and Control Subcommittee, November 2012.

Table 1: Classification of Devices		
Initiate Actions to Clear Faults or Mitigate Abnormal System Conditions to Support Reliable Operation of the Bulk-Power System	**Initiate Action for Abnormal Equipment Conditions for Purposes other than Supporting Reliable Operation of the Bulk-Power System**	**Monitor the Health of Individual Equipment and Provide Information that is Advisory in Nature**
Sudden Pressure (63) (when utilized in a trip application)	• Overspeed Device (12) • Underspeed Device (14) • Apparatus Thermal Device (26) • Flame Detector (28) • Bearing Protective Device (38) • Mechanical Condition Monitor (39) • Atmospheric Condition Monitor (45) • Machine or Transformer Thermal Relay (49) • Density Switch or Sensor (61) • Pressure Switch (63) (other than sudden pressure relays utilized in trip application • Level Switch (71)	• Apparatus Thermal Device (26) • Bearing Protective Device (38) • Mechanical Condition Monitor (39) • Atmospheric Condition Monitor (45) • Machine or Transformer Thermal Relay (49) • Density Switch or Sensor (61) • Pressure Switch (63) (other than sudden pressure relays utilized in trip application • Level Switch (71)

Chapter 2 – Sudden Pressure Relays

Maintenance Intervals and Activities

In order to determine present industry practices related to sudden pressure relay maintenance, the SPCS conducted a survey of Transmission Owners and Generator Owners in all eight Regions requesting information related to their maintenance practices. The SPCS received responses from 75 Transmission Owners and 109 Generator Owners. Note that, for the purpose of the survey, sudden pressure relays included the following: the “sudden pressure relay” (SPR) originally manufactured by Westinghouse, the “rapid pressure rise relay” (RPR) manufactured by Qualitrol, and a variety of Buchholz relays. A copy of the survey is included in Appendix C.

Table 2 provides a summary of the results of the responses:

Table 2: Sudden Pressure Relay Maintenance Practices – Survey Results

	Transmission Owner	Generator Owner
Number of responding owners that trip with Sudden Pressure Relays:	67	84
Percentage of responding owners who trip that have a Maintenance Program:	75%	78%
Percentage of maintenance programs that include testing the pressure actuator:	81%	77%
Average Maintenance interval reported:	5.9 years	4.9 years

Additionally, in order to validate the information noted above, the SPCS contacted the following entities for their feedback: the IEEE Power System Relaying Committee, the IEEE Transformer Committee, the Doble Transformer Committee, the NATF System Protection Practices Group, and the EPRI Generator Owner/Operator Technical Focus Group. All of these organizations indicated the results of the SPCS survey are consistent with their respective experiences.

Pressure Actuator Testing

The pressure actuator can take several forms; however, the basic function is to detect a sudden pressure increase within the transformer that is outside of the normal pressure changes that would occur due to expansion and contraction of the oil as a result of external temperature changes or heating due to loading. These devices can be installed at various locations on the transformer and, depending on location, may require the equipment to be removed from service prior to testing the device.

The SPCS also assessed the maintenance activities included in Table 1-1 of PRC-005-2 and concluded that the activities necessary for sudden pressure relay maintenance and testing are analogous to activities performed during maintenance and testing of electromechanical protective relays identified in Table 1-1: Protective Relay.

Sudden Pressure Control Circuitry

The only control circuitry associated with the sudden pressure relays is the circuit which trips the breaker or other interrupting device. As noted in the Supplementary Reference and FAQ document associated with PRC-005-2, maintenance and testing of this circuitry is already included in the requirements of the revised standard. The SPCS believes activities and intervals for maintenance and testing of sudden pressure control circuitry should be explicitly stated in the associated Table 1-5: Control Circuitry Associated With Protective Functions.

Chapter 3 – Recommendations

Based on its analysis, the SPCS has determined the only device that responds to non-electrical quantities that should be included in PRC-005 is a sudden pressure relay that trips the equipment it is monitoring. Therefore, the SPCS recommends the following guidance for future development of NERC Reliability Standard PRC-005, Protection System Maintenance, to address the concerns stated in FERC Order No. 758.

Modify PRC-005 to explicitly address maintenance and testing of the actuator device of the sudden pressure relay when applied as a protective device that trips a facility described in the applicability section of the Reliability Standard.

- Develop minimum maintenance activities for sudden pressure relays similar to Table 1-1: Protective Relay. Based on the survey results, the SPCS recommends the maximum interval for time-based maintenance programs be 6 years.
- Modify Table 1-5: "Control Circuitry Associated With Protective Functions" to explicitly include the sudden pressure control circuitry.

Appendix A – Attachment to NERC Informational Filing in Response to FERC Order No. 758 – April 12, 2012

ATTACHMENT A

NERC System Protection and Control Subcommittee
Tentative Schedule for Activities Related to
Paragraph 15 of FERC Order No. 758

February 2012 – May 2012	Develop a list of devices to be addressed in a subsequent revision of PRC-005 (use the IEEE device list as a reference of possible devices to be considered)
	Document devices considered and recommendations for which items are/are not to be included
May 2012 – May 2013	Work with IEEE Power System Relaying Committee and IEEE Transformer Committee regarding minimum maintenance activities and maximum intervals for those devices recommended for inclusion in PRC-005
	Review manufacturer's literature and recommended maintenance practices
	Conduct a survey, possibly through the Transmission Forum, of maintenance practices for identified devices
May 2013 – September 2013	Develop a report to NERC Planning Committee
September 2013 – December 2013	NERC Planning Committee review and approval
First Quarter 2014	Submit technical document(s) to NERC Standards Committee

Prepared by the NERC System Protection and Control Subcommittee

March 15, 2011

Appendix B – IEEE Device Numbers and Functions

The devices in switching equipment are referred to by numbers, according to the functions they perform. These numbers are based on a system which has been adopted as standard for automatic switchgear by IEEE. This system is used on connection diagrams, in instruction books, and in specifications.

1 – Master element

An initiating device, such as a control switch, voltage relay, float switch etc., that serves either directly, or through such permissive devices as protective and time-delay relays, to place an equipment in or out of operation.

2 – Time-delay starting or closing relay

A device that functions to give a desired amount of time delay before or after any point of operation in a switching sequence or protective relay system, except as specifically provided by device functions 48, 62 and 79 described later.

3 – Checking or interlocking relay

A device that operates in response to the position of a number of other devices, (or to a number of predetermined conditions), in an equipment to allow an operating sequence to proceed, to stop, or to provide a check of the position of these devices or of these conditions for any purpose.

4 – Master contactor

A device, generally controlled by device No. 1 or equivalent, and the required permissive and protective devices, that serve to make and break the necessary control circuits to place an equipment into operation under the desired conditions and to take it out of operation under other or abnormal conditions.

5 – Stopping device

A control device used primarily to shut down an equipment and hold it out of operation. [This device may be manually or electrically actuated, but excludes the function of electrical lockout (see device function 86) on abnormal conditions.]

6 – Starting circuit breaker

A device whose principal function is to connect a machine to its source of starting voltage.

7 – Rate-of-rise relay

A relay that functions on an excessive rate of rise of current.

8 – Control power disconnecting device

A disconnecting device, such as a knife switch, circuit breaker, or pull-out fuse block, used for the purpose of respectively connecting and disconnecting the source of control power to and from the control bus or equipment.

9 – Reversing device

A device is used for the purpose of reversing a machine field or for performing any other reversing functions.

10 – Unit sequence switch

A switch used to change the sequence in which units may be placed in and out of service in multiple-unit equipment.

11 – Multifunction device

A device that performs three or more comparatively important functions that could only be designated by combining several of these device function numbers. All of the functions performed by device 11 shall be defined in the drawing legend or device function list.

12 – Over speed device

A device, usually a direct connected speed switch, that functions on machine over speed.

13 – Synchronous-speed device
A device s such as a centrifugal speed switch, a slip frequency relay, a voltage relay, an undercurrent relay, or any other type of device that operates at approximately the synchronous speed of a machine.

14 – Underspeed device
A device that functions when the speed of a machine falls below a pre-determined value.

15 – Speed or frequency matching device
A device that functions to match and hold the speed or the frequency of a machine or of a system equal to, or approximately equal to, that of another machine, source, or system.

16 – Reserved for future application

17 – Shunting or discharge switch
A switch that serves to open or to close a shunting circuit around any piece of apparatus (except a resistor), such as a machine field, a machine armature, a capacitor, or a reactor.

Note: This excludes devices that perform such shunting operations as may be necessary in the process of starting a machine by devices 6 or 42, or their equivalent, and also excludes device 73 function that serves for the switching of resistors.

18 – Accelerating or decelerating device
A deice used to close or to cause the closing of circuits that are used to increase or decrease the speed of a machine.

19 – Starting-to-running transition
A contactor that operates to initiate or cause the automatic transfer of a machine from the starting to the running power connection.

20 – Electrically operated valve
An electrically operated, controlled, or monitored valve used in a fluid, air, gas, or vacuum line.

Note: The function of the valve may be indicated by the use of suffixes.

21 – Distance relay
A relay that functions when the circuit admittance, impedance, or reactance increases or decreases beyond a predetermined value.

22 – Equalizer circuit breaker
A breaker that serves to control or to make and break the equalizer or the current balancing connections for a machine field, or for regulating equipment, in a multiple unit installation.

23 – Temperature control device
A device that functions to raise or to lower the temperature of a machine or other apparatus, or of any medium, when its temperature falls below or rises above a predetermined value.

Note: An example is a thermostat that switches on a space heater in a switchgear assembly when the temperature falls to a desired value as distinguished from a device that is used to provide automatic temperature regulation between close limits and would be designated as 90T.

24 – Volts per hertz relay
A relay that functions when the ratio of voltage to frequency exceeds a preset value. The relay may have an instantaneous or a time characteristic.

25 – Synchronizing or synchronism check
A device that operates when two ac circuits are within the desired limits of frequency, phase angle, or voltage to permit or to cause the paralleling of these two circuits.

26 – Apparatus thermal device
Functions when the temperature of the protected apparatus (other than the load-carrying windings of machines and transformers as covered by device function number 49) or of a liquid or other medium exceeds a predetermined value; or when the temperature of the protected apparatus or of any medium decreases below a predetermined value.

27 – Under voltage relay
A relay that operates when its input voltage is less than a predetermined value.

28 – Flame detector
A device that monitors the presence of the pilot or main flame in such apparatus as a gas turbine or a steam boiler.

29 – Isolating contactor
A device used expressly for disconnecting one circuit from another for the purposes of emergency operation, maintenance, or test.

30 – Annunciator relay
A non-automatically reset device that gives a number of separate visual indications upon the functioning of protective devices and that may also be arranged to perform a lock-out function.

31 – Separate excitation device
A device that connects a circuit, such as the shunt field of a synchronous converter, to a source of separate excitation during the starting sequence; or one which energizes the excitation and ignition circuits of a power rectifier.

32 – Directional power relay
A relay that operates on a predetermined value of power flow in a given direction or upon reverse power flow such as that resulting from the motoring of a generator upon loss of its prime mover.

33 – Position switch
A switch that makes or breaks contact when the main device or piece of apparatus that has no device function number reaches a given position.

34 – Master sequence device
A device such as a motor operated multi contact switch, or the equivalent, or a programming device, such as a computer, that establishes or determines the operating sequence of the major devices in an equipment during starting and stopping or during other sequential switching operations.

35 – Brush-operating or slip-ring short circuiting
A device used for raising, lowering or shifting the brushes of a machine; short-circuiting its slip rings; or engaging or disengaging the contacts of a mechanical rectifier.

36 – Polarity or polarizing voltage device
A device that operates, or permits the operation of, another device on a predetermined polarity only or that verifies the presence of a polarizing voltage in an equipment.

37 – Undercurrent or under power relay
A device that functions when the current or power flow decreases below a predetermined value.

38 – Bearing protective device
A device that functions on excessive bearing temperature or on other abnormal mechanical conditions associated with the bearing, such as undue wear, which may eventually result in excessive bearing temperature or failure.

39- Mechanical condition monitor
A device that functions upon the occurrence of an abnormal mechanical condition (except that associated with bearings as covered under device function 38), such as excessive vibration, eccentricity, expansion, shock, tilting, or seal failure.

40 – Field relay
A relay that functions on a given or abnormally low value or failure of machine field current, or on an excessive value of the reactive component of armature current in an ac machine indicating abnormally low field excitation.

41 – Field circuit breaker
A device that functions to apply or remove the field excitation of a machine.

42 – Running circuit breaker
A device whose principal function is to connect a machine to its source of running or operating voltage. This function may also be used for a device, such as a contactor, that is used in series with a circuit breaker or other fault protecting means, primarily for frequent opening and closing of the circuit.

43 – Manual transfer or selector device
A manually operated device that transfers the control circuits in order to modify the plan of operation of the switching equipment or of some of the devices.

44 – Unit sequence starting relay
A relay that functions to start the next available unit in multiple unit equipment upon the failure or nonavailability of the normally preceding unit.

45 – Atmospheric condition monitor
A device that functions upon the occurrence of an abnormal atmospheric condition, such as damaging fumes, explosive mixtures, smoke, or fire.

46 – Reverse-phase or phase-balance
A current relay is a relay that functions when the polyphase currents are of reverse phase sequence or when the polyphase currents are unbalanced or contain negative phase-sequence components above a given amount.

47 – Phase-sequence or phase-balance
A voltage relay that functions upon a predetermined value of polyphase voltage in the desired phase sequence, or when the polyphase voltages are unbalanced, or when the negative phase-sequence voltage exceeds a given amount.

48 – Incomplete sequence relay
A relay that generally returns the equipment to the normal, or off, position and locks it out if the normal starting, operating, or stopping sequence is not properly completed within a predetermined time. If the device is used for alarm purposes only, it should preferably be designated as 48A (alarm).

49 – Machine or transformer thermal
A relay that functions when the temperature of a machine armature winding or other load-carrying winding or element of a machine or power transformer exceeds a predetermined value.

50 – Instantaneous over current relay
A relay that functions instantaneously on an excessive value of current.

51 – Ac time over current relay
A relay with either a definite or inverse time characteristic that functions when the ac input current exceeds a predetermined value, and in which the input current and operating time are independently related or inversely related through a substantial portion of the performance range.

52 – Ac circuit breaker
A device that is used to close and interrupt an ac power circuit under normal conditions or to interrupt this circuit under fault or emergency conditions.

53 – Exciter or dc generator relay
A relay that forces the dc machine field excitation to build up during starting or that functions when the machine voltage has built up to a given value.

54 – Turning gear engaging device
An electrically operated, controlled, or monitored device that functions to cause the turning gear to engage (or disengage) the machine shaft.

55 – Power factor relay
A relay that operates when the power factor in an ac circuit rises above or falls below a predetermined value.

56 – Field application relay
A relay that automatically controls the application of the field excitation to an ac motor at some predetermined point in the slip cycle.

57 – Short-circuiting or grounding device
A primary circuit switching device that functions to short circuit or ground a circuit in response to automatic or manual means.

58 – Rectification failure relay
A device that functions if a power rectifier fails to conduct or block properly.

59 – Over voltage relay
A relay that operates when its input voltage is higher than a predetermined value.

60 – Voltage or current balance relay
A relay that operates on a given difference in voltage, or current input or output, of two circuits.

61 – Density switch or sensor
A device that operates on a given value, or a given rate of change, of gas density.

62 – Time-delay stopping or opening relay
A time-delay relay that serves in conjunction with the device that initiates the shutdown, stopping, or opening operation in an automatic sequence or protective relay system.

63 – Pressure switch
A switch that operates on given values, or on a given rate of change, of pressure.

64 – Ground detector relay
A relay that operates upon failure of machine or other apparatus insulation to ground, or on flashover of a dc machine to ground.

Note: This function is assigned only to a relay which detects the flow of current from the frame of a machine or enclosing case or structure of a piece of apparatus to ground, or detects a ground on a normally ungrounded winding or circuit. It is not applied to a device connected in the secondary neutral of a current transformer, or in the secondary neutral of current transformers, connected in the power circuit of a normally grounded system.

65 – Governor
The assembly of fluid, electrical, or mechanical control equipment used for regulating the flow of water, steam, or other media to the prime mover for such purposes as starting, holding speed or load, or stopping.

66 – Notching or jogging device
A device that functions to allow only a specified number of operations of a given device or equipment, or a specified number of successive operations within a given time of each other. It is also a device that functions to energize a circuit

periodically or for fractions of specified time intervals, or that is used to permit intermittent acceleration or jogging of a machine at low speeds for mechanical positioning.

67 – Ac directional over current relay
A relay that functions on a desired value of ac over current flowing in a predetermined direction.

68 – Blocking relay
A relay that initiates a pilot signal for blocking of tripping on external faults in a transmission line or in other apparatus under predetermined conditions, or that cooperates with other devices to block tripping or to block reclosing on an out-of-step condition or on power swings.

69 – Permissive control device
Generally, a two-position device that in one position permits the closing of a circuit
breaker, or the placing of an equipment into operation, and in the other position prevents the circuit breaker or the equipment from being operated.

70 – Rheostat
A variable resistance device used in an electric circuit which is electrically operated or has other electrical accessories, such as auxiliary, position, or limit switches.

71 – Level switch
A switch that operates on given values, or on a given rate of change, of level.

72 – Dc circuit breaker
A circuit breaker used to close and interrupt a dc power circuit under normal conditions or to interrupt this circuit under fault or emergency conditions.

73 – Load-resistor contactor
A contactor used to shunt or insert a step of load limiting, shifting, or indicating resistance in a power circuit, or to switch a space heater in circuit, or to switch a light, or regenerative load resistor of a power rectifier or other machine in and out of circuit.

74 – Alarm relay
A relay other than an annunciator, as covered under device function 30, that is used to operate, or that operates in connection with, a visual or audible alarm.

75 – Position changing mechanism
A mechanism that is used for moving a main device from one position to another in an equipment; for example, shifting a removable circuit breaker unit to and from the connected, disconnected, and test positions.

76 – Dc over current relay
A relay that functions when the current in a dc circuit exceeds a given value.

77 – Telemetering device
A transmitter used to generate and transmit to a remote location an electrical signal representing a measured quantity, or a receiver used to receive the electrical signal from a remote transmitter and convert the signal to represent the original measured quantity.

78 – Phase-angle measuring or out-of step
A relay that functions at a predetermined phase angle between two voltages, or between two currents, or between voltage and current.

79 – Ac reclosing relay
A relay that controls the automatic reclosing and locking out of an ac circuit interrupter.

80 – Flow switch
A switch that operates on given values, or on a given rate of change, of flow.

81 – Frequency relay
A relay that responds to the frequency of an electrical quantity, operating when the frequency or rate of change of frequency exceeds or is less than a predetermined value.

82 – Dc load-measuring reclosing relay
A relay that controls the automatic closing and reclosing of a dc circuit interrupter, generally in response to load circuit conditions.

83 – Automatic selective control or transfer relay
A relay that operates to select automatically between certain sources or conditions in equipment or that performs a transfer operation automatically.

84 – Operating mechanism
The complete electrical mechanism or servomechanism, including the operating motor, solenoids, position switches, etc., for a tap changer, induction regulator, or any similar piece of apparatus that otherwise has no device function number.

85 – Carrier or pilot-wire receiver relay
A relay that is operated or restrained by a signal used in connection with carrier-current or dc pilot-wire fault directional relaying.

86 – Lockout relay
An electrically operated hand or electrically reset auxiliary relay that is operated upon the occurrence of abnormal conditions to maintain associated equipment or devices out of service until it is reset.

87 – Differential protective relay
A protective relay that functions on a percentage, or phase angle, or other quantitative difference between two currents or some other electrical quantities.

88 – Auxiliary motor or motor generator
A device used for operating auxiliary equipment, such as pumps, blowers, exciters, rotating magnetic amplifiers, etc.

89 – Line switch
Used as a disconnecting, load interrupter, or isolating switch in an ac or dc power circuit. (This device function number is normally not necessary unless the switch is electrically operated or has electrical accessories, such as an auxiliary switch, a magnetic lock, etc.)

90 – Regulating device
Functions to regulate a quantity or quantities, such as voltage, current, power, speed, frequency, temperature, and load, at a certain value or between certain (generally close) limits for machines, tie lines, or other apparatus.

91 – Voltage directional relay
A relay that operates when the voltage across an open circuit breaker or contactor exceeds a given value in a given direction.

92 – Voltage and power directional relay
A relay that permits or causes the connection of two circuits when the voltage difference between them exceeds a given value in a predetermined direction and causes these two circuits to be disconnected from each other when the power flowing between them exceeds a given value in the opposite direction.

93 – Field-changing contactor
Functions to increase or decrease, in one step, the value of field excitation on a machine.

94 – Tripping or trip-free relay

Functions to trip a circuit breaker, contactor, or equipment, or to permit immediate tripping by other devices; or to prevent immediate reclosing of a circuit interrupter if it should open automatically, even though its closing circuit is maintained closed.

95, 96, 97, 98, 99 –

Used only for specific applications on individual installations where none of the assigned numbered functions from 1 to 94 is suitable.

Appendix C – Initial Screening of Devices

Table C-1: Initial Screening of Devices			
Device Number	**Function**	**Categorization per Step 1 – Analysis of Individual Devices**	**Further Analysis**
1	Master Element	Control device	No
2	Time-Delay Starting or Closing Relay	Typically a control device When used in a protection system, an auxiliary relay addressed by the protection system definition and subject to PRC-005 if applied on an applicable facility	No
3	Checking or Interlocking Relay	Control device	No
4	Master Contactor	Control device	No
5	Stopping Device	Control device	No
6	Starting Circuit Breaker	Primary equipment	No
7	Rate-of-rise Relay	Protective relay addressed by the protection system definition and subject to PRC-005 if applied on an applicable facility (generally an integral part of a more complex protective relay)	No
8	Control Power Disconnecting Device	Control device	No
9	Reversing Device	Control device	No
10	Unit Sequence Switch	Control device	No
11	Multifunction Device	Protective relay addressed by the protection system definition and subject to PRC-005 if applied on an applicable facility	No
12	Overspeed Device	Identified for further analysis – see Appendix D	Yes
13	Synchronous-Speed Device	Control device	No
14	Underspeed Device	Identified for further analysis – see Appendix D	Yes
15	Speed or Frequency Matching Device	Control device	No
16	(Reserved For Future Application)	Not applicable	—
17	Shunting or Discharge-Switch	Control device	No
18	Accelerating or Decelerating Device	Control device	No

Table C-1: Initial Screening of Devices			
Device Number	Function	Categorization per Step 1 – Analysis of Individual Devices	Further Analysis
19	Starting-to-Running Transition Contactor	Control device	No
20	Electrically Operated Valve	Primary equipment	No
21	Distance Relay	Protective relay addressed by the protection system definition and subject to PRC-005 if applied on an applicable facility	No
22	Equalizer Circuit Breaker	Control device	No
23	Temperature Control Device	Control device	No
24	Volts-per-Hertz Relay	Protective relay addressed by the protection system definition and subject to PRC-005 if applied on an applicable facility	No
25	Synchronizing or Synchronism Check	Subject of separate report by SAMS and SPCS	No
26	Apparatus Thermal Device	Identified for further analysis – see Appendix D	Yes
27	Undervoltage Relay	Protective relay addressed by the protection system definition and subject to PRC-005 if applied on an applicable facility	No
28	Flame Detector	Identified for further analysis – see Appendix D	Yes
29	Isolating Contactor	Control device	No
30	Annunciator Relay	Generally provides information that is advisory in nature When used in a protection system, an auxiliary relay addressed by the protection system definition and subject to PRC-005 if applied on an applicable facility	No
31	Separate Excitation Device	Control device	No
32	Directional Power Relay	Protective relay addressed by the protection system definition and subject to PRC-005 if applied on an applicable facility	No
33	Position Switch	Control device	No
34	Master Sequence Device	Control device	No
35	Brush-Operating or Slip-Ring Short-Circuiting Device	Control device	No
36	Polarity or Polarizing Voltage Device	Control device	No
37	Undercurrent or Underpower Relay	Protective relay addressed by the protection system definition and subject to PRC-005 if applied on an applicable facility	No
38	Bearing Protective Device	Identified for further analysis – see Appendix D	Yes

Table C-1: Initial Screening of Devices			
Device Number	**Function**	**Categorization per Step 1 – Analysis of Individual Devices**	**Further Analysis**
39	Mechanical Condition Monitor	Identified for further analysis – see Appendix D	Yes
40	Field Relay	Protective relay addressed by the protection system definition and subject to PRC-005 if applied on an applicable facility	No
41	Field Circuit Breaker	Primary equipment	No
42	Running Circuit Breaker	Primary Equipment	No
43	Manual Transfer or Selector Device	Control device	No
44	Unit Sequence Starting Relay	Control device	No
45	Atmospheric Condition Monitor	Identified for further analysis – see Appendix D	Yes
46	Reverse-Phase or Phase-Balance Current Relay	Protective relay addressed by the protection system definition and subject to PRC-005 if applied on an applicable facility	No
47	Phase-Sequence or Phase Balance Voltage Relay	Protective relay addressed by the protection system definition and subject to PRC-005 if applied on an applicable facility	No
48	Incomplete Sequence Relay	Control device	No
49	Machine or Transformer Thermal Relay	Identified for further analysis – see Appendix D	Yes
50	Instantaneous Overcurrent	Protective relay addressed by the protection system definition and subject to PRC-005 if applied on an applicable facility	No
51	AC Time Overcurrent Relay	Protective relay addressed by the protection system definition and subject to PRC-005 if applied on an applicable facility	No
52	AC Circuit Breaker	Primary Equipment	No
53	Exciter or DC Generator Relay	Control device	No
54	Turning Gear Engaging Device	Control device	No
55	Power-Factor Relay	Control device	No
56	Field Application Relay	Control device	No
57	Short-Circuiting or Grounding Device	Primary equipment	No
58	Rectification Failure Relay	Protective relay addressed by the protection system definition and subject to PRC-005 if applied on an applicable facility	No

Table C-1: Initial Screening of Devices			
Device Number	**Function**	**Categorization per Step 1 – Analysis of Individual Devices**	**Further Analysis**
59	Overvoltage Relay	Protective relay addressed by the protection system definition and subject to PRC-005 if applied on an applicable facility	No
60	Voltage or Current Balance Relay	Protective relay addressed by the protection system definition and subject to PRC-005 if applied on an applicable facility	No
61	Density Switch or Sensor	Identified for further analysis – see Appendix D	Yes
62	Time-delay Stopping or Opening Relay	Auxiliary relay addressed by the protection system definition and subject to PRC-005 if applied on an applicable facility	No
63	Pressure Switch	Identified for further analysis – see Appendix D	Yes
64	Ground Detector Relay	Protective relay addressed by the protection system definition and subject to PRC-005 if applied on an applicable facility	No
65	Governor	Control device	No
66	Notching or Jogging Device	Control device	No
67	AC Directional Overcurrent Relay	Protective relay addressed by the protection system definition and subject to PRC-005 if applied on an applicable facility	No
68	Blocking Relay	Protective relay addressed by the protection system definition and subject to PRC-005 if applied on an applicable facility	No
69	Permissive Control Device	Control device	No
70	Rheostat	Control device	No
71	Level Switch	Identified for further analysis – see Appendix D	Yes
72	DC Circuit Breaker	Primary equipment	No
73	Load-Resistor Contactor	Control device	No
74	Alarm Relay	Provides information that is advisory in nature	No
75	Position-Changing Mechanism	Control device	No
76	DC Overcurrent Relay	Protective relay addressed by the protection system definition and subject to PRC-005 if applied on an applicable facility	No
77	Telemetering Device	Control device	No
78	Phase-Angle Measuring or Out-Of-Step Protective Relay	Protective relay addressed by the protection system definition and subject to PRC-005 if applied on an applicable facility	No
79	AC Reclosing Relay	Subject of separate report by SAMS and SPCS	No
80	Flow Switch	Control device	No

Table C-1: Initial Screening of Devices			
Device Number	**Function**	**Categorization per Step 1 – Analysis of Individual Devices**	**Further Analysis**
81	Frequency Relay	Protective relay addressed by the protection system definition and subject to PRC-005 if applied on an applicable facility	No
82	DC Load-Measuring Reclosing Relay	Protective relay addressed by the protection system definition and subject to PRC-005 if applied on an applicable facility	No
83	Automatic Selective Control or Transfer Relay	Control device	No
84	Operating Mechanism	Control device	No
85	Carrier or Pilot-Wire Receiver Relay	Protective relay addressed by the protection system definition and subject to PRC-005 if applied on an applicable facility	No
86	Lockout Relay	Auxiliary relay addressed by the protection system definition and subject to PRC-005 if applied on an applicable facility	No
87	Differential Protective Relay	Protective relay addressed by the protection system definition and subject to PRC-005 if applied on an applicable facility	No
88	Auxiliary Motor or Motor Generator	Primary equipment	No
89	Line Switch	Primary equipment	No
90	Regulating Device	Control device	No
91	Voltage Directional Relay	Protective relay addressed by the protection system definition and subject to PRC-005 if applied on an applicable facility	No
92	Voltage And Power Directional Relay	Protective relay addressed by the protection system definition and subject to PRC-005 if applied on an applicable facility	No
93	Field-Changing Contactor	Control device	No
94	Tripping or Trip-Free Relay	Auxiliary relay addressed by the protection system definition and subject to PRC-005 if applied on an applicable facility	No
95	(Reserved For Special Application)	Not applicable	—
96	(Reserved For Special Application)	Not applicable	—
97	(Reserved For Special Application)	Not applicable	—
98	(Reserved For Special Application)	Not applicable	—
99	(Reserved For Special Application)	Not applicable	—

Appendix D – Detailed Assessment of Devices

The SPCS reviewed a list of all IEEE/ANSI device numbers and discussed each device type. After eliminating devices already addressed by the revised definition of Protection System and devices that are clearly not protective devices, such as primary equipment and control devices, detailed analysis was performed for the following list of devices:

- Overspeed Device (12)
- Underspeed Device (14)
- Apparatus Thermal Device (26)
- Flame Detector (28)
- Bearing Protective Device (38)
- Mechanical Condition Monitor (39)
- Atmospheric Condition Monitor (45)
- Machine or Transformer Thermal Relay (49)
- Density Switch or Sensor (61)
- Pressure Switch (63)
- Level Switch (71)

For each device, a summary of the evaluation and conclusion is presented. As a result of this analysis, the SPCS concludes that the only devices responding to non-electrical quantities that should be included in the applicability of PRC-005 are sudden pressure relays utilized in a tripping function. When applied in a tripping function, these devices initiate actions to clear faults to support reliable operation of the Bulk-Power System. The other devices evaluated respond to abnormal equipment conditions and take action to protect equipment from mechanical or thermal damage or premature loss of life, rather than for the purpose of initiating fault clearing or mitigating an abnormal system condition to support reliable operation of the Bulk-Power System. Thus, these devices are not recommended for inclusion in PRC-005. The SPCS recognizes that devices that respond to abnormal equipment conditions perform an important function. However, these devices do not directly support NERC's mission to ensure the reliability of the Bulk-Power System.

Overspeed (12): Usually a direct-connected speed switch that functions on machine over speed.

Action taken: This device provides an alarm, and in some cases trips the affected equipment, in response to the equipment operating at an excessive speed. This device is set to operate after an electrical device responding to frequency, which is set at a lower threshold.

Impact of inadvertent operation: Inadvertent operation would result in a nuisance alarm, unnecessary control action, or unnecessarily removing the equipment from service. In some cases, the device is applied to primary equipment, while in other cases, it may be applied to ancillary equipment such as a fan or motor. The impact of removing BES equipment from service would be the same as for a TPL-002-0b Category B contingency, "Loss of an Element without a Fault," for which the system is designed and operated to withstand.

Impact of failure to operate: Overspeed protection responds to an abnormal operating condition rather than a fault and, for generator applications, typically is not expected to operate when the generator is connected to the system, thereby limiting the potential impact to the Bulk-Power System. A failure to operate could result in damage to the generator prime mover depending on what other protection or controls operate to remove the unit from service, but would not result in removal of other elements from service.

Risk of inadvertent operation during a disturbance: The overspeed device directly measures the speed of the machine. Therefore, an overspeed device should only operate during a fault or abnormal system condition if an actual overspeed condition occurs (e.g., due to a loss of synchronism) or if an independent failure of the device occurs. There is no operating experience in which misoperation of an overspeed device in response to a system disturbance has contributed to a cascading event.

Conclusion: This device responds to an abnormal equipment condition and takes action to protect the equipment from mechanical damage rather than for the purpose of initiating fault clearing or mitigating an abnormal system condition to support reliable operation of the Bulk-Power System.

Underspeed (14): A device that functions when the speed of a machine falls below a pre-determined value.

Action taken: This device provides an alarm, and in some cases trips the affected equipment, in response to the equipment operating at insufficient speed. This device is set to operate after an electrical device responding to frequency, which is set at a higher threshold.

Impact of inadvertent operation: Inadvertent operation would result in a nuisance alarm, unnecessary control action, or unnecessarily removing the equipment from service. In some cases, the device is applied to primary equipment, while in other cases, it may be applied to ancillary equipment such as a fan or motor. The impact of removing BES equipment from service would be the same as for a TPL-002-0b Category B contingency, “Loss of an Element without a Fault,” for which the system is designed and operated to withstand.

Impact of failure to operate: Underspeed protection responds to an abnormal operating condition rather than a fault. A failure to operate could result in damage to the generator prime mover depending on what other protection or controls operate to remove the unit from service, but would not result in removal of other elements from service.

Risk of inadvertent operation during a disturbance: The underspeed device directly measures the speed of the machine. Therefore, an underspeed device should only operate during a fault or abnormal system condition if an actual underspeed condition occurs (e.g., due to a loss of synchronism) or if an independent failure of the device occurs. There is no operating experience in which misoperation of an underspeed device in response to a system disturbance has contributed to a cascading event.

Conclusion: This device responds to an abnormal equipment condition and takes action to protect the equipment from mechanical damage rather than for the purpose of initiating fault clearing or mitigating an abnormal system condition to support reliable operation of the Bulk-Power System.

Apparatus thermal device (26): Functions when the temperature of the protected apparatus (other than the load-carrying windings of machines and transformers as covered by device function number 49) or of a liquid or other medium (e.g., transformer top oil temperature, which may be the most prevalent) exceeds a predetermined value; or when the temperature of the protected apparatus or of any medium decreases below a predetermined value.

Action taken: This device provides an alarm, and in some cases trips the affected equipment, in response to the equipment operating at an elevated temperature that may result in increased loss of life.

Impact of inadvertent operation: Inadvertent operation would result in a nuisance alarm or unnecessarily removing the equipment from service. The impact of removing the equipment from service would be the same as for a TPL-002-0b Category B contingency, “Loss of an Element without a Fault,” for which the system is designed and operated to withstand.

Impact of failure to operate: Failure to alarm or trip the equipment could lead to loss of life or equipment damage resulting from operation at elevated temperature.

Risk of inadvertent operation during a disturbance: The apparatus thermal device directly measures the temperature of the of the protected apparatus or medium. Therefore, an apparatus thermal device should only operate during a fault or abnormal system condition if the actual temperature is outside its operating limits or if an independent failure of the device occurs. There is no operating experience in which misoperation of an apparatus thermal device in response to a system disturbance has contributed to a cascading event.

Conclusion: This device responds to an abnormal equipment condition and takes action to protect the equipment from excessive loss of life rather than for the purpose of initiating fault clearing or mitigating an abnormal system condition to support reliable operation of the Bulk-Power System.

Flame detector (28): A device that monitors the presence of the pilot or main flame in such apparatus as a gas turbine or a steam boiler.

Action taken: This device initiates a control action to remove the fuel source from a gas turbine or steam turbine boiler in response to a loss of combustion.

Impact of inadvertent operation: Inadvertent operation would result in a nuisance alarm or unnecessarily removing the equipment from service. The impact of removing the equipment from service would be the same as for a TPL-002-0b Category B contingency, "Loss of an Element without a Fault," for which the system is designed and operated to withstand.

Impact of failure to operate: The flame detector responds to an abnormal operating condition rather than a fault. A failure to operate could result in an uncontrolled delivery of fuel that is not consumed, but would not result in removal of other elements from service.

Risk of inadvertent operation during a disturbance: The flame detector indirectly measures the presence of a flame; however, this is done by monitoring heat or radiation from the flame, which are both independent of power system conditions. Therefore, a flame detector should only operate during a fault or abnormal system condition for an actual loss of flame (e.g., flameout in a combustion turbine) or if an independent failure of the device occurs. There is no operating experience in which misoperation of a flame detector in response to a system disturbance has contributed to a cascading event.

Conclusion: This device responds to an abnormal equipment condition and takes action to protect the equipment from mechanical damage rather than for the purpose of initiating fault clearing or mitigating an abnormal system condition to support reliable operation of the Bulk-Power System.

Bearing protective device (38): Functions on excessive bearing temperature or on other abnormal mechanical conditions associated with the bearing, such as undue wear, which may eventually result in excessive bearing temperature or failure.

Action taken: This device provides an alarm, and in some cases trips the affected equipment, in response to an abnormal condition such as the bearing operating at an elevated temperature. The device typically alarms at one level. When tripping is provided, such as for a hydraulic unit thrust bearing, it trips at a second level.

Impact of inadvertent operation: Inadvertent operation would result in a nuisance alarm or unnecessarily removing the equipment from service. The impact of removing the equipment from service would be the same as for a TPL-002-0b Category B contingency, "Loss of an Element without a Fault," for which the system is designed and operated to withstand.

Impact of failure to operate: Failure to alarm or trip the equipment could lead to loss of life or excessive wear, and may eventually lead to failure of the bearing.

Risk of inadvertent operation during a disturbance: The bearing protective device indirectly measures the temperature or other physical condition of the bearing; however, this is done by monitoring mechanical quantities in proximity to the bearing which are independent of power system conditions. Therefore, a bearing protective device should only operate during a fault or abnormal system condition for an actual bearing problem or if an independent failure of the device occurs. There is no operating experience in which misoperation of a bearing protective device in response to a system disturbance has contributed to a cascading event.

Conclusion: This device responds to an abnormal equipment condition and takes action to protect the equipment from excessive loss of life or eventual failure rather than for the purpose of initiating fault clearing or mitigating an abnormal system condition to support reliable operation of the Bulk-Power System.

Mechanical condition monitor (39): A device that functions upon the occurrence of an abnormal mechanical condition (except that associated with bearings as covered under device function 38), such as excessive vibration, eccentricity, expansion, shock, tilting, or seal failure.

Action taken: This device provides an alarm, and in some cases trips the affected equipment, in response to an abnormal mechanical condition of the equipment. The device typically alarms at one level, and either provides a second alarm or trips at a second level.

Impact of inadvertent operation: Inadvertent operation would result in a nuisance alarm or unnecessarily removing the equipment from service. The impact of removing the equipment from service would be the same as for a TPL-002-0b Category B contingency, "Loss of an Element without a Fault," for which the system is designed and operated to withstand.

Impact of failure to operate: Failure to alarm or trip the equipment could lead to loss of life or equipment damage.

Risk of inadvertent operation during a disturbance: The mechanical condition monitor indirectly measures the physical condition of the protected device; however, this is done by monitoring mechanical quantities in proximity to the device which are independent of power system conditions. Therefore, a mechanical condition monitor should only operate during a fault or abnormal system condition for an actual mechanical problem or if an independent failure of the device occurs. There is no operating experience in which misoperation of a mechanical condition in response to a system disturbance has contributed to a cascading event.

Conclusion: This device responds to an abnormal equipment condition and takes action to protect the equipment from excessive loss of life or eventual failure rather than for the purpose of initiating fault clearing or mitigating an abnormal system condition to support reliable operation of the Bulk-Power System.

Atmospheric condition monitor (45): A device that functions upon the occurrence of an abnormal atmospheric condition, such as damaging fumes, explosive mixtures, smoke, or fire.

Action taken: This device provides an alarm or shuts down a process and prevents restarting until normal atmospheric conditions are restored.

Impact of inadvertent operation: Inadvertent operation would result in a nuisance alarm or unnecessarily shutting down a process. When shutting down a process results in removing equipment from service, the impact would be the same as for a TPL-002-0b Category B contingency, "Loss of an Element without a Fault," for which the system is designed and operated to withstand.

Impact of failure to operate: Failure to alarm or trip the equipment could lead to an unsafe operating condition and the potential for equipment damage.

Risk of inadvertent operation during a disturbance: The atmospheric condition monitor directly or indirectly measures atmospheric conditions; however, even indirect measurement is accomplished by monitoring atmospheric conditions local to the equipment. Therefore, an atmospheric condition monitor should only operate during a fault or abnormal system condition if the power system event affected atmospheric conditions, or if an independent failure of the monitor occurs. There is no operating experience in which misoperation of an atmospheric condition monitor in response to a system disturbance has contributed to a cascading event.

Conclusion: This device responds to an abnormal equipment condition and takes action to protect the equipment from excessive loss of life rather than for the purpose of initiating fault clearing or mitigating an abnormal system condition to support reliable operation of the Bulk-Power System.

Machine or transformer thermal relay (49): A relay that functions when the temperature of a machine armature winding or other load-carrying winding or element of a machine or power transformer exceeds a predetermined value.

Action taken: This device provides an alarm, and in some cases trips the affected equipment, in response to the equipment operating at an elevated temperature that may result in increased loss of life.

Impact of inadvertent operation: Inadvertent operation would result in a nuisance alarm or unnecessarily removing the equipment from service. The impact of removing the equipment from service would be the same as for a TPL-002-0b Category B contingency, "Loss of an Element without a Fault," for which the system is designed and operated to withstand.

Impact of failure to operate: Failure to alarm or trip the equipment could lead to loss of life resulting from operation at elevated temperature.

Risk of inadvertent operation during a disturbance: The machine or transformer thermal relay indirectly measures the temperature of the of the winding; however, this is accomplished by measuring the temperature of the medium in which the winding is contained. Therefore, a thermal relay should only operate during a fault or abnormal system condition if the calculated temperature is outside its operating limits or if an independent failure of the relay occurs. There is no operating experience in which misoperation of a thermal relay in response to a system disturbance has contributed to a cascading event.

Conclusion: This device responds to an abnormal equipment condition and takes action to protect the equipment from excessive loss of life rather than for the purpose of initiating fault clearing or mitigating an abnormal system condition to support reliable operation of the Bulk-Power System.

Density switch or sensor (61)[5]: A device that operates on a given value, or a given rate of change, of gas density.

Action taken: This device activates a visual indicator and/or switch to provide an alarm in response to a change in gas density within the equipment it is monitoring. In some cases, activation of a switch associated with this device, trips, or blocks tripping of, the affected equipment.

Impact of inadvertent operation: Inadvertent operation would result in a nuisance alarm or unnecessarily removing the equipment from service. The impact of removing the equipment from service would be the same as for a TPL-002-0b Category B contingency, "Loss of an Element without a Fault," for which the system is designed and operated to withstand.

Impact of failure to operate: Failure to alarm, trip, or lockout the equipment could lead to loss of life resulting from operation at low gas density levels.

Risk of inadvertent operation during a disturbance: The density switch or sensor may directly or indirectly measure gas density; however, even indirect measurement is accomplished by measuring both pressure and temperature of the gas. Therefore, a density switch or sensor should only operate during a fault or abnormal system condition if the gas density is outside its operating limits or if an independent failure of the switch or sensor occurs. There is no operating experience in which misoperation of a density switch or sensor in response to a system disturbance has contributed to a cascading event.

[5] Gas density is affected by changes in pressure and temperature. Gas density monitors are modified pressure measuring instruments with electrical accessories. Gas density monitors typically combine both measuring and switching functions in one single instrument. Because gas density is strongly affected by changes in pressure, the switching functions provided with a gas density monitor are often labeled "63" rather than "61".

Conclusion: This device responds to an abnormal equipment condition and takes action to protect the equipment from excessive loss of life rather than for the purpose of initiating fault clearing or mitigating an abnormal system condition to support reliable operation of the Bulk-Power System.

Pressure switch (63): A switch that operates on given values, or on a given rate of change, of pressure.

Action taken: This device provides an alarm, and in some cases trips the affected equipment, in response to changes in pressure within a device such as a circuit breaker or transformer.

Impact of inadvertent operation: Inadvertent operation would result in a nuisance alarm or unnecessarily removing the equipment from service. The impact of removing the equipment from service would be the same as for a TPL-002-0b Category B contingency, "Loss of an Element without a Fault," for which the system is designed and operated to withstand.

Impact of failure to operate: Failure to alarm or trip the equipment could lead to unavailability of the equipment, loss of life resulting from operation at low pressure, or extended exposure to fault current.

Risk of inadvertent operation during a disturbance: The pressure switch directly measures pressure of the monitored medium. A pressure switch should only operate during a fault or abnormal system condition if a pressure exceeds the level necessary to operate the device. In some applications, such as transformer sudden pressure relays used to detect faults internal to a transformer, the pressure switch may operate due to a pressure change associated with through-fault current caused by an external fault. There is no operating experience in which misoperation of a pressure switch in response to a system disturbance has contributed to a cascading event; however, inadvertent operation for an external fault could result in tripping additional system elements.

Conclusion: This device responds to an abnormal equipment condition, such as low gas or air pressure, as well as rapid pressure rises associated with faults in oil-filled equipment (e.g., transformers and shunt reactors). Where this device is applied to respond to abnormal equipment conditions, it takes action to protect the equipment from excessive loss of life or to indicate unavailability of service, rather than for the purpose of initiating fault clearing or mitigating an abnormal system condition to support reliable operation of the Bulk-Power System. Where the device is installed to respond to rapid pressure rise in facilities described in the applicability section of Reliability Standard PRC-005, and configured to take action to initiate fault clearing to support reliable operation of the Bulk-Power System, it should be included as a device to be maintained and tested.

Level switch (71): A switch that operates on given values, or on a given rate of change, of level.

Action taken: This device provides an alarm, and in some cases trips the affected equipment, in response to changes in level within the equipment it is monitoring.

Impact of inadvertent operation: Inadvertent operation would result in a nuisance alarm or unnecessarily removing the equipment from service. The impact of removing the equipment from service would be the same as for a TPL-002-0b Category B contingency, "Loss of an Element without a Fault," for which the system is designed and operated to withstand.

Impact of failure to operate: Failure to alarm, or trip the equipment could lead to loss of life resulting from operation at undesirable levels.

Risk of inadvertent operation during a disturbance: The level switch directly measures liquid level in a device. Therefore, a level switch should only operate during a fault or abnormal system condition if the level is outside its operating limits or if an independent failure of the switch occurs. There is no operating experience in which misoperation of a level switch in response to a system disturbance has contributed to a cascading event.

Conclusion: This device responds to an abnormal equipment condition and takes action to protect the equipment from excessive loss of life rather than for the purpose of initiating fault clearing or mitigating an abnormal system condition to support reliable operation of the Bulk-Power System.

Appendix E – SPCS Sudden Pressure Relay Survey

NERC System Protection and Control Subcommittee (SPCS)

Questionnaire on Maintenance Practices for Fault Pressure Relays
(Sudden Pressure, Rapid Pressure Rise, Buchholz, etc)

Purpose: The SPCS is seeking industry input concerning present industry practices related to the maintenance and testing of Fault Pressure Relays (relays which operate on pressure changes caused by faults) applied on Transmission equipment. This survey pertains specifically to three types of relays:

- Sudden Pressure Relay (SPR)- these devices are mounted on the outside of the transformer and operate on an increase in gas pressure.
- Rapid Pressure Rise Relay (RPR)- these devices are mounted on the outside of the transformer and operate on an increase in oil pressure.
- Buchholz relays- these devices are mounted on some oil-filled power transformers and reactors, equipped with an external overhead oil reservoir called a conservator and detect when oil flows rapidly into the conservator.

Company Name: ____

Survey response from: Transmission _____ Generation _____ Both _____

Note: If practices are different for Transmission and Generation, please provide separate responses

1. Does your company utilize Fault Pressure Relays in the 'trip' application?
   SPR Yes_____ No _____
   RPR Yes_____ No _____
   Buchholz Yes_____ No _____

2. Does your company have a 'maintenance' program in place for these devices?
   SPR Yes _____ No _____
   RPR Yes _____ No _____
   Buchholz Yes_____ No _____
3. Does your company's 'maintenance' program include verifying the trip circuit associated with the Fault Pressure Relay?
   Yes____ No ____ N/A _____ If Yes, what is the prescribed or expected interval. ________

4. Does your company's 'maintenance' program include verifying the operation of the 'pressure actuation' portion of the Sudden Pressure Relay?
   SPR Yes______ No _____ If Yes, prescribed or expected interval? ______
   RPR Yes______ No _____ If Yes, prescribed or expected interval? ______
   Buchholz Yes_____ No _____ If Yes, prescribed or expected interval? ______

   If Yes, does your company simulate an 'operate' and a 'non-operate' condition with some form of pressure test? Yes______ No ____

5. Are there any other activities that are included in the maintenance of Sudden Pressure Relays?
   Yes____ No _____ If so, please describe:

6. Does your company use another type of Fault Pressure Relay not listed above? Yes ____ No _____
   If so, please describe:

Appendix F – System Protection and Control Subcommittee

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Principal Engineer
Exelon Corporation

Philip B. Winston
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Chief Engineer, Protection and Control
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RE – FRCC
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Exhibit E

SPCS Supplemental Report: ***Sudden Pressure Relays and Other Devices that Respond to Non-Electrical Quantities***

Sudden Pressure Relays and Other Devices that Respond to Non-Electrical Quantities

Supplemental Information to Support Project 2007-17.3: Protection System Maintenance and Testing
October 31, 2014

Background

The NERC System Protection and Control Subcommittee (SPCS) provided input to Project 2007-17.3 Protection System Maintenance and Testing – Phase 3 (Sudden Pressure Relays) in response to FERC Order No. 758. The SPCS report, *Sudden Pressure Relays and Other Devices that Respond to Non-Electrical Quantities: SPCS Input for Standard Development in Response to FERC Order No. 758* ("SPCS Report"), was approved by the NERC Planning Committee on December 11, 2013. In the report, the SPCS evaluated all devices on the IEEE list of device numbers to identify which devices that respond to non-electrical quantities may impact reliable operation of the bulk power system.

As a result of this analysis, the SPCS concluded the only devices responding to non-electrical quantities that should be included in the applicability of PRC-005 are sudden pressure relays utilized in a tripping function. When applied in a tripping function, these devices initiate actions to clear faults to support reliable operation of the bulk power system. The other devices evaluated respond to abnormal equipment conditions and take action to protect equipment from mechanical or thermal damage, or premature loss of equipment life, rather than for the purpose of initiating fault clearing or mitigating an abnormal system condition to support reliable operation of the bulk power system.

The Project 2007-17.3 standard drafting team has implemented the SPCS recommendations for inclusion of sudden pressure relays, and corresponding minimum maintenance activities and maximum maintenance intervals, in proposed standard PRC-005-4. During development of the proposed standard, the drafting team has received questions as to whether additional devices should be included to address the FERC concern stated in Order No. 758.[1] Specifically, questions have focused on turbine generator vibration monitors and circuit breaker arc extinguishing systems. In this supplemental report, the SPCS provides additional information on events during which these devices operated or failed to operate, and additional analysis on whether these devices should be included in the applicability of PRC-005.

[1] *Interpretation of Protection System Reliability Standard*, Order No. 758, 138 FERC ¶ 61,094 (2012) ("Order No. 758") at P 15, FERC directed development of technical documents proposed by NERC in its NOPR comments, including the identification of devices that are designed to sense or take action against any abnormal system condition that will affect reliable operation.

Evaluation of Devices

Turbine Generator Vibration Monitors

Turbine generator vibration monitors fall under the category of mechanical condition monitors (device number 39), which includes devices that detect excessive vibration. The SPCS noted in its previous analysis that these devices provide an alarm, and in some cases trip the affected equipment, in response to an abnormal mechanical condition of the equipment.[2] The SPCS analysis demonstrated that these devices do not impact reliable operation because:

- Inadvertent operation would result in a nuisance alarm or unnecessarily removing the equipment from service. The impact of removing the equipment from service would be the same as for a TPL-002-0b Category B contingency, "Loss of an Element without a Fault,"[3] which the system is designed and operated to withstand.
- Failure to alarm or trip the equipment would only affect the monitored equipment, potentially resulting in loss of equipment life or equipment damage.
- They are not susceptible to operating in response to adverse system conditions because these devices monitor mechanical quantities in proximity to the device which are independent of power system conditions.

The SPCS further noted there is no operating experience in which misoperation of a mechanical condition monitor in response to a system disturbance has contributed to a cascading event.

The SPCS has provided further validation with research of events during which turbine generator vibration monitors operated or failed to operate. SPCS members reviewed events within their respective Regions and consulted with NERC Event Analysis staff, and identified two events during which turbine generator vibration monitors operated.

In the first event, a communication failure in a distributed control system resulted in a common-mode trip of three generating units at one plant. The event occurred during a scheduled outage of a fourth unit at the plant to replace the network router connecting a vibration monitoring system to its control system. The network router was configured incorrectly and caused a "data storm" in the network upon connecting the router's power supply. Upon disconnecting the new router to clear the problem, the control system processors for the other three generating units rebooted, leading to false vibration signals that initiated turbine trip signals for the three affected generating units. The communication system failure occurred as a direct result of the work being performed with an immediately observable failure mode that was corrected. Given the nature of the event, the failure could not have remained undetected and caused or contributed to a subsequent event.

[2] SPCS Report at p. 29.

[3] TPL-002-0b is presently subject to enforcement. This condition is addressed by similar or more severe Planning Events P1 and P2 in TPL-001-4, which is subject to future enforcement, with a staged implementation plan beginning on January 1, 2015.

In the second event, a turbine generator vibration monitoring device operated after a power load imbalance (PLU)[4] function operated to close the turbine's steam control valves. Upon closing of the steam valves, the vibration monitor detected vibration of the generating unit and initiated a trip. In this case, the vibration monitor operated as designed in response to actual vibration of the generating unit.

The SPCS has reviewed its previous assessment of mechanical condition monitors in light of these two events. The first event was an isolated event that did not occur in response to a system disturbance, and the second event was incidental in that the PLU operation occurred in response to the system disturbance and the vibration monitor responded to an actual vibration resulting from the PLU operation. Based on this assessment, the SPCS reaffirms that failure of a vibration monitor would not affect reliable operation of the bulk power system. This device responds to an abnormal equipment condition and takes action to protect the equipment from excessive loss of equipment life or eventual failure rather than for the purpose of initiating fault clearing or mitigating an abnormal system condition to support reliable operation of the bulk power system.

Circuit Breaker Arc Extinguishing Systems

The SPCS notes that circuit breaker arc extinguishing systems are comprised of many components and focused its review on the devices that are designed to sense or take action against an abnormal system condition. In this context, the SPCS identified the pressure switches (device number 61)[5] as the device subject to consideration under Order No. 758. The SPCS noted in its previous analysis that these devices activate a visual indicator and/or switch to provide an alarm in response to a change in gas density within the equipment it is monitoring. In some cases, such as circuit breakers, activation of a switch associated with this device trips, or blocks tripping of, the affected equipment.[6] The SPCS analysis demonstrated that these devices do not impact reliable operation because:

- Inadvertent operation would result in a nuisance alarm or unnecessarily removing the equipment from service. The impact of removing the equipment from service would be the same as for a TPL-002-0b Category B contingency, "Loss of an Element without a Fault," which the system is designed and operated to withstand.
- Failure to alarm, trip, or lockout the equipment would only lead to loss of equipment life resulting from operation at low gas density levels.
- The density switch or sensor may directly or indirectly measure gas density; however, even indirect measurement is accomplished by measuring both pressure and temperature of the gas. Therefore, a density switch or sensor should only operate during a fault or abnormal system condition if the gas density is outside its operating limits or if an independent failure of the switch or sensor occurs.

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[4] The PLU function typically triggers a rapid closing of the steam valves, reducing mechanical power input to zero, thereby preventing further acceleration of the unit. The valves are subsequently reopened if the PLU condition clears.

[5] The devices used measure gas density, which is affected by changes in pressure and temperature. Gas density monitors are modified pressure measuring instruments with electrical accessories. Gas density monitors typically combine both measuring and switching functions in one single instrument. Because gas density is strongly affected by changes in pressure, the switching functions provided with a gas density monitor are often labeled "63" (pressure switch) rather than "61" (density switch or sensor).

[6] SPCS Report at p. 30.

The SPCS further noted there is no operating experience in which misoperation of a density switch or sensor in response to a system disturbance has contributed to a cascading event.

The SPCS has provided further validation with research of events during which circuit breaker arc extinguishing systems operated or failed to operate. SPCS members reviewed events within their respective Regions and consulted with NERC Event Analysis staff, and identified one event in which cold weather caused breakers to open on low SF_6 pressure and a second event in which cold weather caused breakers to open on low air pressure. The low SF6 pressure occurred during maintenance on a station service breaker that resulted in a loss of station service to heaters on the circuit breakers. The low air pressure occurred due to a rapid drop in ambient temperature. In these events the pressure switches operated as designed to trip the affected breakers.

The SPCS has reviewed its previous assessment of density switches and sensors in light of these two events. While the previous assessment addressed pressure switches in general, the SPCS has further assessed the impact of an inadvertent operation or failure to operate specific to pressure switches applied on circuit breakers. The events analyzed by the SPCS did not occur in response to a system disturbance. In both cases, operation of the pressure switches operated due to the gas density or pressure being outside established operating limits. In the event an independent failure results in inadvertent operation of a pressure switch the result will be opening the breaker, or blocking tripping of the breaker and possibly bypassing the breaker failure timer, depending on the design practice of the entity owning the circuit breaker. If the breaker is tripped an element may be removed from service or one terminal of a transmission line or transformer may be opened; however, the SPCS notes that for many bus configurations, the only impact will be opening a circuit breaker with no effect on transmission system power flow. If tripping is blocked and a fault occurs, the breaker failure protection will operate to clear the fault. Both of these scenarios are contingencies addressed by design and operating criteria. In the event an independent failure prevents operation of the pressure switch during a drop in pressure and a fault occurs, the result will be either (i) normal fault clearing if the breaker is capable of interrupting the fault current, or (ii) breaker failure clearing and possible damage to the circuit breaker. The result will be independent of whether the failed device was intended to trip or to block tripping and bypass the breaker failure timer; however, in either case the resulting scenario is a contingency addressed by design and operating criteria. Thus inadvertent operation or a failure to operate will not affect reliable operation of the bulk power system. Based on this assessment, the SPCS reaffirms that failure of a pressure switch, including those applied on circuit breakers, would not affect reliable operation of the bulk power system. This device responds to an abnormal equipment condition and takes action to protect the equipment from excessive loss of equipment life rather than for the purpose of initiating fault clearing or mitigating an abnormal system condition to support reliable operation of the bulk power system.

Conclusion

Upon review of the previous SPCS recommendations and specific events involving turbine generator vibration and circuit breaker arc extinguishing systems, the SPCS reaffirms its recommendation that the only devices that respond to non-electrical quantities that should be included in the applicability of PRC-005 are sudden pressure relays utilized in a tripping function. When applied in a tripping function, sudden pressure relays initiate actions to clear faults to support reliable operation of the bulk power system. The two devices evaluated above respond to abnormal equipment conditions and take action to protect equipment from mechanical damage or premature loss of equipment life, rather than for the purpose of initiating fault clearing or mitigating an abnormal system condition to support reliable operation of the bulk power system.

Exhibit F

Supplementary Reference and FAQ Document

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Supplementary Reference and FAQ

PRC-005-4 Protection System Maintenance and Testing

October 2014

RELIABILITY | ACCOUNTABILITY

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1. Introduction and Summary

Note: This supplementary reference for PRC-005-4 is neither mandatory nor enforceable.

NERC currently has four Reliability Standards that are mandatory and enforceable in the United States and Canada and address various aspects of maintenance and testing of Protection and Control Systems.

These standards are:

PRC-005-1b — Transmission and Generation Protection System Maintenance and Testing

PRC-008-0 — Underfrequency Load Shedding Equipment Maintenance Programs

PRC-011-0 — UVLS System Maintenance and Testing

PRC-017-0 — Special Protection System Maintenance and Testing

While these standards require that applicable entities have a maintenance program for Protection Systems, and that these entities must be able to demonstrate they are carrying out such a program, there are no specifics regarding the technical requirements for Protection System maintenance programs. Furthermore, FERC Order 693 directed additional modifications respective to Protection System maintenance programs. PRC-005-3 will replace PRC-005-2 which combined and replaced PRC-005, PRC-008, PRC-011 and PRC-017. PRC-005-3 adds Automatic Reclosing to PRC-005-2. PRC-005-2 addressed these directed modifications and replaces PRC-005, PRC-008, PRC-011 and PRC-017.

FERC Order 758 further directed that maintenance of reclosing relays and sudden pressure relays that affect the reliable operation of the Bulk Power System be addressed. PRC-005-3 addresses this directive regarding reclosing relays, and, when approved, will supersede PRC-005-2. PRC-005-4 addresses this directive regarding sudden pressure relays and, when approved, will supersede PRC-005-3.

This document augments the Supplementary Reference and FAQ previously developed for PRC-005-2 by including discussion relevant to Automatic Reclosing added in PRC-005-3 and Sudden Pressure Relaying in PRC-005-4.

2. Need for Verifying Protection System Performance

Protective relays have been described as silent sentinels, and do not generally demonstrate their performance until a Fault or other power system problem requires that they operate to protect power system Elements, or even the entire Bulk Electric System (BES). Lacking Faults, switching operations or system problems, the Protection Systems may not operate, beyond static operation, for extended periods. A Misoperation - a false operation of a Protection System or a failure of the Protection System to operate, as designed, when needed - can result in equipment damage, personnel hazards, and wide-area Disturbances or unnecessary customer outages. Maintenance or testing programs are used to determine the performance and availability of Protection Systems.

Typically, utilities have tested Protection Systems at fixed time intervals, unless they had some incidental evidence that a particular Protection System was not behaving as expected. Testing practices vary widely across the industry. Testing has included system functionality, calibration of measuring devices, and correctness of settings. Typically, a Protection System must be visited at its installation site and, in many cases, removed from service for this testing.

Fundamentally, a Reliability Standard for Protection System Maintenance and Testing requires the performance of the maintenance activities that are necessary to detect and correct plausible age and service related degradation of the Protection System components, such that a properly built and commissioned Protection System will continue to function as designed over its service life.

Similarly station batteries, which are an important part of the station dc supply, are not called upon to provide instantaneous dc power to the Protection System until power is required by the Protection System to operate circuit breakers or interrupting devices to clear Faults or to isolate equipment.

2.1 Existing NERC Standards for Protection System Maintenance and Testing

For critical BES protection functions, NERC standards have required that each utility or asset owner define a testing program. The starting point is the existing Standard PRC-005, briefly restated as follows:

Purpose: To document and implement programs for the maintenance of all Protection Systems affecting the reliability of the Bulk Electric System (BES) so that these Protection Systems are kept in working order.

PRC-005-4 is not specific on where the boundaries of the Protection Systems lie. However, the definition of Protection System in the NERC Glossary of Terms used in Reliability Standards indicates what must be included as a minimum.

At the beginning of the project to develop PRC-005-2, the definition of Protection System was:

Protective relays, associated communications Systems, voltage and current sensing devices, station batteries and dc control circuitry.

Applicability: Owners of generation and transmission Protection Systems.

Requirements: The owner shall have a documented maintenance program with test intervals. The owner must keep records showing that the maintenance was performed at the specified intervals.

2.2 Protection System Definition

The most recently approved definition of Protection Systems is:

- Protective relays which respond to electrical quantities,
- Communications systems necessary for correct operation of protective functions,
- Voltage and current sensing devices providing inputs to protective relays,
- Station dc supply associated with protective functions (including station batteries, battery chargers, and non-battery-based dc supply), and
- Control circuitry associated with protective functions through the trip coil(s) of the circuit breakers or other interrupting devices.

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:

"*…that are installed for the purpose of detecting Faults on BES Elements (lines, buses, transformers, etc.).*"

The drafting team intends that this standard will follow with any definition of the Bulk Electric System. There should be no ambiguity; if the Element is a BES Element, then the Protection System protecting that Element should then be included within this standard. If there is regional variation to the definition, then there will be a corresponding regional variation to the Protection Systems that fall under this standard.

There is no way for the Standard Drafting Team to know whether a specific 230KV line, 115KV line (even 69KV line), for example, should be included or excluded. Therefore, the team set the clear intent that the standard language should simply be applicable to Protection Systems for BES Elements.

The BES is a NERC defined term that, from time to time, may undergo revisions. Additionally, there may even be regional variations that are allowed in the present and future definitions. See the NERC Glossary of Terms for the present, in-force definition. See the applicable Regional Reliability Organization for any applicable allowed variations.

While this standard will undergo revisions in the future, this standard will not attempt to keep up with revisions to the NERC definition of BES, but, rather, simply make BES Protection Systems applicable.

The Standard is applied to Generator Owners (GO) and Transmission Owners (TO) because GOs and TOs have equipment that is BES equipment. The standard brings in Distribution Providers (DP) because, depending on the station configuration of a particular substation, there may be

Protection System equipment installed at a non-transmission voltage level (Distribution Provider equipment) that is wholly or partially installed to protect the BES. PRC-005-4 would apply to this equipment. An example is underfrequency load-shedding, which is frequently applied well down into the distribution system to meet PRC-007-0.

PRC-005-2 replaced the existing PRC-005, PRC-008, PRC-011 and PRC-017. Much of the original intent of those standards was carried forward whenever it was possible to continue the intent without a disagreement with FERC Order 693. For example, the original PRC-008 was constructed quite differently than the original PRC-005. The drafting team agrees with the intent of this and notes that distributed tripping schemes would have to exhibit multiple failures to trip before they would prove to be significant, as opposed to a single failure to trip of, for example, a transmission Protection System Bus Differential lock-out relay. While many failures of these distribution breakers could add up to be significant, it is also believed that distribution breakers are operated often on just Fault clearing duty; and, therefore, the distribution circuit breakers are operated at least as frequently as stipulated in any requirement in this standard.

Additionally, since PRC-005-2 replaced PRC-011, it will be important to make the distinction between under-voltage Protection Systems that protect individual Loads and Protection Systems that are UVLS schemes that protect the BES. Any UVLS scheme that had been applicable under PRC-011 is now applicable under PRC-005-2. An example of an under-voltage load-shedding scheme that is not applicable to this standard is one in which the tripping action was intended to prevent low distribution voltage to a specific Load from a Transmission system that was intact except for the line that was out of service, as opposed to preventing a Cascading outage or Transmission system collapse.

It had been correctly noted that the devices needed for PRC-011 are the very same types of devices needed in PRC-005.

Thus, a standard written for Protection Systems of the BES can easily make the needed requirements for Protection Systems, and replace some other standards at the same time.

2.3.1 Frequently Asked Questions:

What exactly is the BES, or Bulk Electric System?

BES is the abbreviation for Bulk Electric System. BES is a term in the Glossary of Terms used in Reliability Standards, and is not being modified within this draft standard.

Why is Distribution Provider included within the Applicable Entities and as a responsible entity within several of the requirements? Wouldn't anyone having relevant Facilities be a Transmission Owner?

Depending on the station configuration of a particular substation, there may be Protection System equipment installed at a non-transmission voltage level (Distribution Provider equipment) that is wholly or partially installed to protect the BES. PRC-005-4 applies to this equipment. An example is underfrequency load-shedding, which is frequently applied well down into the distribution system to meet PRC-007-0.

We have an under voltage load-shedding (UVLS) system in place that prevents one of our distribution substations from supplying extremely low voltage in the case of a specific transmission line outage. The transmission line is part of the BES. Does this mean that our UVLS system falls within this standard?

The situation, as stated, indicates that the tripping action was intended to prevent low distribution voltage to a specific Load from a Transmission System that was intact, except for the line that was out of service, as opposed to preventing Cascading outage or Transmission System Collapse.

This standard is not applicable to this UVLS.

We have a UFLS or UVLS scheme that sheds the necessary Load through distribution-side circuit breakers and circuit reclosers. Do the trip-test requirements for circuit breakers apply to our situation?

No. Distributed tripping schemes would have to exhibit multiple failures to trip before they would prove to be significant, as opposed to a single failure to trip of, for example, a transmission Protection System bus differential lock-out relay. While many failures of these distribution breakers could add up to be significant, it is also believed that distribution breakers are operated often on just Fault clearing duty; and, therefore, the distribution circuit breakers are operated at least as frequently as any requirements that might have appeared in this standard.

We have a UFLS scheme that, in some locales, sheds the necessary Load through non-BES circuit breakers and, occasionally, even circuit switchers. Do the trip-test requirements for circuit breakers apply to our situation?

If your "non-BES circuit breaker" has been brought into this standard by the inclusion of UFLS requirements, and otherwise would not have been brought into this standard, then the answer is that there are no trip-test requirements. For these devices that are otherwise non-BES assets, these tripping schemes would have to exhibit multiple failures to trip before they would prove to be as significant as, for example, a single failure to trip of a transmission Protection System bus differential lock-out relay.

How does the "Facilities" section of "Applicability" track with the standards that will be retired once PRC-005-2 becomes effective?

In establishing PRC-005-2, the drafting team combined legacy standards PRC-005-1b, PRC-008-0, PRC-011-0, and PRC-017-0. The merger of the subject matter of these standards is reflected in Applicability 4.2.

The intent of the drafting team is that the legacy standards be reflected in PRC-005-2 as follows:

- Applicability of PRC-005-1b for Protection Systems relating to non-generator elements of the BES is addressed in 4.2.1;
- Applicability of PRC-008-0 for underfrequency load shedding systems is addressed in 4.2.2;
- Applicability of PRC-011-0 for undervoltage load shedding relays is addressed in 4.2.3;
- Applicability of PRC-017-0 for Remedial Action Systems is addressed in 4.2.4;
- Applicability of PRC-005-1b for Protection Systems for BES generators is addressed in 4.2.5.

2.4 Applicable Relays

The NERC Glossary definition has a Protection System including relays, dc supply, current and voltage sensing devices, dc control circuitry and associated communications circuits. The relays to which this standard applies are those protective relays that respond to electrical quantities and provide a trip output to trip coils, dc control circuitry or associated communications equipment. This definition extends to IEEE Device No. 86 (lockout relay) and IEEE Device No. 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.

Relays that respond to non-electrical inputs or impulses (such as, but not limited to, vibration, seismic, thermal or gas accumulation) are not included.

Automatic Reclosing is addressed in PRC-005-3 by explicitly addressing them outside the definition of Protection System. The specific locations for applicable Automatic Reclosing are addressed in Applicability Section 4.2.6.

Sudden Pressure Relaying is addressed in PRC-005-4 by explicitly addressing them outside the definition of Protection System. The specific locations for applicable Sudden Pressure Relaying are addressed in Applicability Section 4.2.1, 4.2.5.2, 4.2.5.3 and 4.2.5.4.

2.4.1 Frequently Asked Questions:

Are power circuit reclosers, reclosing relays, closing circuits and auto-restoration schemes covered in this Standard?

Yes. Automatic Reclosing includes reclosing relays and the associated dc control circuitry. Section 4.2.6 of the Applicability specifically limits the applicable reclosing relays to:

4.2.6 Automatic Reclosing

4.2.6.1 Automatic Reclosing applied on the terminals of Elements connected to the BES bus located at generating plant substations where the total installed gross generating plant capacity is greater than the gross capacity of the largest BES generating unit within the Balancing Authority Area or, if a member of a Reserve Sharing Group, the largest generating unit within the Reserve Sharing Group.

4.2.6.2 Automatic Reclosing applied on the terminals of all BES Elements at substations one bus away from generating plants specified in Section 4.2.6.1 when the substation is less than 10 circuit-miles from the generating plant substation.

4.2.6.3 Automatic Reclosing applied as an integral part of aRAS specified in Section 4.2.4. Further, Footnote 1 to Applicability Section 4.2.6 establishes that Automatic Reclosing addressed in 4.2.6.1 and 4.2.6.2 may be excluded if the equipment owner can demonstrate that a close-in three-phase fault present for twice the normal clearing time (capturing a minimum trip-close-trip time delay) does not result in a total loss of gross generation in the Interconnection exceeding the gross capacity of the largest relevant BES generating unit where the Automatic Reclosing is applied.

Additionally, Footnote 2 to Applicability Section 4.2.6.1 advises that the entity's PSMP needs to remain current regarding the applicability of Automatic Reclosing Components relative to the largest generating unit within the Balancing Authority Area or Reserve Sharing Group.

The Applicability as detailed above was recommended by the NERC System Analysis and Modeling Subcommittee (SAMS) after a lengthy review of the use of reclosing within the BES. SAMS concluded that automatic reclosing is largely implemented throughout the BES as an operating convenience, and that automatic reclosing mal-performance affects BES reliability only when the reclosing is part of a Remedial Action System, or when premature autoreclosing has the potential to cause generating unit or plant instability. A technical report, "Considerations for Maintenance and Testing of Autoreclosing Schemes — November 2012", is referenced in PRC-005-3 and provides a more detailed discussion of these concerns.

Why did the standard drafting team not include IEEE device numbers to describe Automatic Reclosing Relays?

The drafting team elected not to include IEEE device numbers to describe Automatic Reclosing because Automatic Reclosing component type could be a stand-alone electromechanical relay; or could be the 79 function within a microprocessor based multi-function relay(11).

Is a sync-check (25) relay included in the Automatic Reclosing Control Circuitry?

Where sync-check relays are included in an Automatic Reclosing scheme that is part of an RAS, the sync-check would be included in the control circuitry (Table 4-2(b)). Where sync-check relays are included in an Automatic Reclosing scheme that is not part of an RAS, the sync-check would not be included in the control circuitry (Table 4-2(a)).

The SDT asserts that a sync-check (25) relay does not initiate closing but rather enables or disables closing and is not considered a part of the actual Automatic Reclosing control circuitry when not part of an RAS.

How do I interpret Applicability Section 4.2.6 to determine applicability in the following examples:

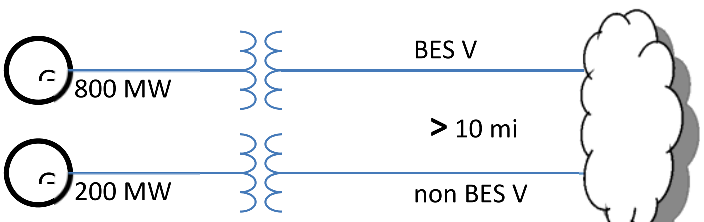
At my generating plant substation, I have a total of 800 MW connected to one voltage level and 200 MW connected to another voltage level. How do I determine my gross capacity? Where do I consider Automatic Reclosing to be applicable?

Scenario number 1:

The 800 MW of generation is connected to a BES voltage level bus, the 200 MW is connected to a non-BES voltage level bus, and there is no connection between the two buses locally or within 10 circuit miles from the generating plant substation. The largest single unit in the BA area is 750 MW.

In this case, the total installed gross generating capacity would be 800 MW. The two units are essentially independent plants.

The BES voltage level bus is considered to be the bus to which the 800 MW of generation is connected. Any BES Automatic Reclosing at this location, as well as other locations within 10 circuit miles, is considered to be applicable because 800 MW exceeds the largest single unit in the BA area.



[Essentially independent plants]

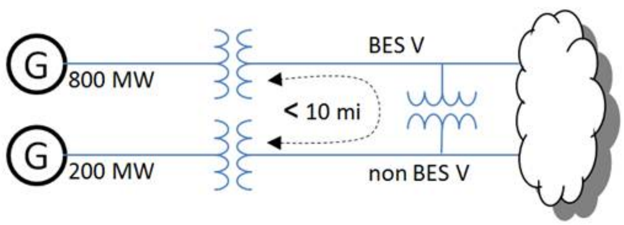
Gross Capacity	**Automatic Reclosing in scope**
800 MW	BES V

Scenario number 2:

The 800 MW of generation is connected to a BES voltage level bus, the 200 MW unit is connected to a non-BES voltage level bus, and there is a connection between the two buses locally or within 10 circuit miles from the generating plant substation. The largest single unit in the BA area is 750 MW.

In this case, reclosing into a fault on the BES system could impact the stability of the non-BES-connected generating units. Therefore, the total installed gross generating capacity would be 1000 MW.

The BES voltage level bus is considered to be the bus to which the 800 MW of generation is connected. Any BES Automatic Reclosing at this location, as well as other locations within 10 circuit miles, is considered to be applicable because total of 1000 MW exceeds the largest single unit in the BA area. However, the Automatic Reclosing on the non-BES voltage level bus is not applicable.



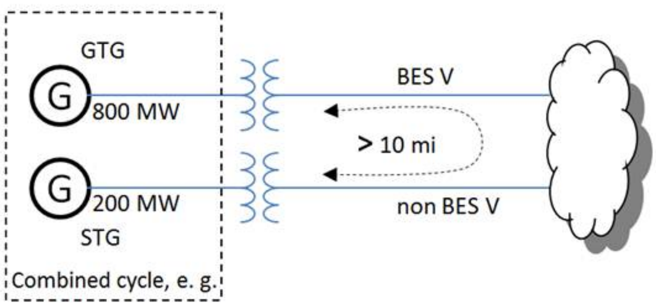
Gross Capacity	**Automatic Reclosing in scope**
1000 MW	BES V

Scenario number 3:

The 800 MW of generation is connected to a BES voltage level bus, the 200 MW unit is connected to a non-BES voltage level bus, and there is no connection between the two buses locally or within 10 circuit miles from the generating plant substation but the generating units connected at the BES voltage level do not operate independently of the units connected at the non BES voltage level (e.g., a combined cycle facility where 800 MW of combustion turbines are connected at a BES voltage level whose exhaust is used to power a 200 MW steam unit connected to a non BES voltage level. The largest single unit in the BA area is 750 MW.

In this case, the total installed gross generating capacity would be 1000 MW. Therefore, reclosing into a fault on the BES voltage level would result in a loss of the 800 MW combustion turbines and subsequently result in the loss of the 200 MW steam unit because of the loss of the heat source to its boiler.

The BES voltage level bus is considered to be the bus to which the 800 MW of generation is connected. Any BES Automatic Reclosing at this location, as well as other locations within 10 circuit miles, is considered to be applicable because total of 1000 MW exceeds the largest single unit in the BA area. However, the Automatic Reclosing on the non-BES voltage level bus is not applicable.



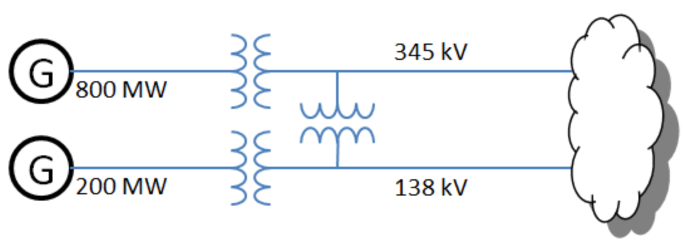
<u>**Gross Capacity**</u>	<u>**Automatic Reclosing in scope**</u>
1000 MW	BES V

Scenario 4

The 800 MW of generation is connected at 345 kV and the 200 MW is connected at 138 kV with an autotransformer at the generating plant substation connecting the two voltage levels. The largest single unit in the BA area is 900 MW.

In this case, the total installed gross generating capacity would be 1000 MW and section 4.2.6.1 would be applicable to both the 345 kV Automatic Reclosing Components and the 138 kV Automatic Reclosing Components, since the total capacity of 1000 MW is larger than the largest single unit in the BA area.

However, if the 345 kV and the 138 kV systems can be shown to be uncoupled such that the 138 kV reclosing relays will not affect the stability of the 345 kV generating units then the 138 kV Automatic Reclosing Components need not be included per section 4.2.6.1.



Gross Capacity	**Automatic Reclosing in scope**
1000 MW	BOTH*

* The study detailed in Footnote 1 of the draft standard may eliminate the 138 kV Automatic Reclosing Components and/or the 345 kV Automatic Reclosing Components

Why does 4.2.6.2 specify "10 circuit miles"?

As noted in "Considerations for Maintenance and Testing of Autoreclosing Schemes — November 2012", transmission line impedance on the order of one mile away typically provides adequate impedance to prevent generating unit instability and a 10 mile threshold provides sufficient margin.

Should I use MVA or MW when determining the installed gross generating plant capacity?

Be consistent with the rating used by the Balancing Authority for the largest BES generating unit within their area.

What value should we use for generating plant capacity in 4.2.6.1?

Use the value reported to the Balance Authority for generating plant capacity for planning and modeling purposes. This can be nameplate or other values based on generating plant limitations such as boiler or turbine ratings.

What is considered to be "one bus away" from the generation?

The BES voltage level bus is considered to be the generating plant substation bus to which the generator step-up transformer is connected. "One bus away" is the next bus, connected by either a transmission line or transformer.

I use my protective relays only as sources of metered quantities and breaker status for SCADA and EMS through a substation distributed RTU or data concentrator to the control center. What are the maintenance requirements for the relays?

This standard addresses Protection Systems that are installed for the purpose of detecting Faults on BES Elements (lines, buses, transformers, etc.). Protective relays, providing only the functions mentioned in the question, are not included.

Are Reverse Power Relays installed on the low-voltage side of distribution banks considered to be components of "Protection Systems that are installed for the purpose of detecting Faults on BES Elements (lines, buses, transformers, etc.)"?

Reverse power relays are often installed to detect situations where the transmission source becomes de-energized and the distribution bank remains energized from a source on the low-voltage side of the transformer and the settings are calculated based on the charging current of the transformer from the low-voltage side. Although these relays may operate as a result of a fault on a BES element, they are not 'installed for the purpose of detecting' these faults.

Why is the maintenance of Sudden Pressure Relaying being addressed in PRC-005-4?

Proper performance of Sudden Pressure Relaying supports the reliability of the BES because fault pressure relays can detect rapid changes in gas pressure, oil pressure, or oil flow that are indicative of faults within liquid-filled, wire-wound equipment such as turn-to-turn faults which may be undetected by Protection Systems. Additionally, Sudden Pressure

Relaying can quickly detect faults and operate to limit damage to liquid-filled, wire-wound equipment.

What type of devices are classified as fault pressure relay?

There are three main types of fault pressure relays; rapid gas pressure rise, rapid oil pressure rise, and rapid oil flow devices.

Rapid gas pressure devices monitor the pressure in the space above the oil (or other liquid), and initiate tripping action for a rapid rise in gas pressure resulting from the rapid expansion of the liquid caused by a fault. The sensor is located in the gas space.

Rapid oil pressure devices monitor the pressure in the oil (or other liquid), and initiate tripping action for a rapid pressure rise caused by a fault. The sensor is located in the liquid.

Rapid oil flow devices ("Buchholz") monitor the liquid flow between a transformer/reactor and its conservator. Normal liquid flow occurs continuously with ambient temperature changes and with internal heating from loading and does not operate the rapid oil flow device. However, when an internal arc happens a sudden expansion of liquid can be monitored as rapid liquid flow from the transformer into the conservator resulting in actuation of the rapid oil flow device.

Are sudden pressure relays that only initiate an alarm included in the scope of PRC-005-4?

No, the definition of Sudden Pressure Relaying specifies only those that trip an interrupting device(s) to isolate the equipment it is monitoring.

Are pressure relief devices included in the scope of PRC-005-4?

No. PRDs are not included in the Sudden Pressure Relaying definition.

Is Sudden Pressure Relaying installed on distribution transformers included in PRC-005-4?

No, Applicability 4.2.1, 4.2.5.2, 4.2.5.3, 4.2.5.4, explicitly describe what Sudden Pressure Relaying is included within the standard.

Are non-electrical sensing devices (other than fault pressure relays) such as low oil level or high winding temperatures included in PRC-005-4?

No, based on the SPCS technical document, "Sudden Pressure Relays and Other Devices that Respond to Non-Electrical Quantities – December 2013," the only applicable non-electrical sensing devices are Sudden Pressure Relays.

The standard specifically mentions auxiliary and lock-out relays. What is an auxiliary tripping relay?

An auxiliary relay, IEEE Device No. 94, is described in IEEE Standard C37.2-2008 as: "A device that functions to trip a circuit breaker, contactor, or equipment; to permit immediate tripping by other devices; or to prevent immediate reclosing of a circuit interrupter if it should open automatically, even though its closing circuit is maintained closed."

What is a lock-out relay?

A lock-out relay, IEEE Device No. 86, is described in IEEE Standard C37.2 as: “A device that trips and maintains the associated equipment or devices inoperative until it is reset by an operator, either locally or remotely.”

3. Protection System and Automatic Reclosing Product Generations

The likelihood of failure and the ability to observe the operational state of a critical Protection System and Automatic Reclosing both depend on the technological generation of the relays, as well as how long they have been in service. Unlike many other transmission asset groups, protection and control systems have seen dramatic technological changes spanning several generations. During the past 20 years, major functional advances are primarily due to the introduction of microprocessor technology for power system devices, such as primary measuring relays, monitoring devices, control Systems, and telecommunications equipment.

Modern microprocessor-based relays have six significant traits that impact a maintenance strategy:

- Self-monitoring capability - the processors can check themselves, peripheral circuits, and some connected substation inputs and outputs, such as trip coil continuity. Most relay users are aware that these relays have self-monitoring, but are not focusing on exactly what internal functions are actually being monitored. As explained further below, every element critical to the Protection System must be monitored, or else verified periodically.
- Ability to capture Fault records showing how the Protection System responded to a Fault in its zone of protection, or to a nearby Fault for which it is required not to operate.
- Ability to meter currents and voltages, as well as status of connected circuit breakers, continuously during non-Fault times. The relays can compute values, such as MW and MVAR line flows, that are sometimes used for operational purposes, such as SCADA.
- Data communications via ports that provide remote access to all of the results of Protection System monitoring, recording and measurement.
- Ability to trip or close circuit breakers and switches through the Protection System outputs, on command from remote data communications messages, or from relay front panel button requests.
- Construction from electronic components, some of which have shorter technical life or service life than electromechanical components of prior Protection System generations.

There have been significant advances in the technology behind the other components of Protection Systems. Microprocessors are now a part of battery chargers, associated communications equipment, voltage and current-measuring devices, and even the control circuitry (in the form of software-latches replacing lock-out relays, etc.).

Any Protection System component can have self-monitoring and alarming capability, not just relays. Because of this technology, extended time intervals can find their way into all components of the Protection System.

This standard also recognizes the distinct advantage of using advanced technology to justifiably defer or even eliminate traditional maintenance. Just as a hand-held calculator does not require routine testing and calibration, neither does a calculation buried in a microprocessor-based device that results in a “lock-out.” Thus, the software-latch 86 that replaces an electro-mechanical 86 does not require routine trip testing. Any trip circuitry associated with the “soft 86” would still need applicable verification activities performed, but the actual “86” does not have to be “electrically operated” or even toggled.

4. Definitions

Protection System Maintenance Program (PSMP) — An ongoing program by which Protection System, Automatic Reclosing and Sudden Pressure Relaying Components are kept in working order and proper operation of malfunctioning Components is restored. A maintenance program for a specific Component includes one or more of the following activities:

- Verify — Determine that the Component is functioning correctly.
- Monitor — Observe the routine in-service operation of the Component.
- Test — Apply signals to a Component to observe functional performance or output behavior, or to diagnose problems.
- Inspect — Detect visible signs of Component failure, reduced performance and degradation.
- Calibrate — Adjust the operating threshold or measurement accuracy of a measuring element to meet the intended performance requirement.

Automatic Reclosing – Includes the following Components:

- Reclosing relay
- Control circuitry associated with the reclosing relay.

Sudden Pressure Relaying – A system that trips an interrupting device(s) to isolate the equipment it is monitoring and includes the following Components:

- Fault pressure relay – a mechanical relay or device that detects rapid changes in gas pressure, oil pressure, or oil flow that are indicative of faults within liquid-filled, wire-wound equipment
- Control circuitry associated with a fault pressure relay

Unresolved Maintenance Issue – A deficiency identified during a maintenance activity that causes the component to not meet the intended performance, cannot be corrected during the maintenance interval, and requires follow-up corrective action.

Segment – Components of a consistent design standard, or a particular model or type from a single manufacturer that typically share other common elements. Consistent performance is expected across the entire population of a Segment. A Segment must contain at least sixty (60) individual Components.

Component Type –

- Any one of the five specific elements of a Protection System.
- Any one of the two specific elements of Automatic Reclosing.
- Any one of the two specific elements of Sudden Pressure Relaying.

Component – Any individual discrete piece of equipment included in a Protection System, Automatic Reclosing, or Sudden Pressure Relaying.

Countable Event – A failure of a Component requiring repair or replacement, any condition discovered during the maintenance activities in Tables 1-1 through 1-5, Table 3, Tables 4-1 through 4-2, and Table 5, which requires corrective action or a Protection System Misoperation attributed to hardware failure or calibration failure. Misoperations due to product design errors, software errors, relay settings different from specified settings, Protection System Component, Automatic Reclosing or Sudden Pressure Relaying configuration or application errors are not included in Countable Events.

4.1 Frequently Asked Questions:

Why does PRC-005-4 not specifically require maintenance and testing procedures, as reflected in the previous standard, PRC-005-1?

PRC-005-1 does not require detailed maintenance and testing procedures, but instead requires summaries of such procedures, and is not clear on what is actually required. PRC-005-4 requires a documented maintenance program, and is focused on establishing requirements rather than prescribing methodology to meet those requirements. Between the activities identified in the Tables 1-1 through 1-5, Table 2, Table 3, and Table 4 (collectively the "Tables"), and the various components of the definition established for a "Protection System Maintenance Program," PRC-005-4 establishes the activities and time basis for a Protection System Maintenance Program to a level of detail not previously required.

Please clarify what is meant by "restore" in the definition of maintenance.

The description of "restore" in the definition of a Protection System Maintenance Program addresses corrective activities necessary to assure that the component is returned to working order following the discovery of its failure or malfunction. The Maintenance Activities specified in the Tables do not present any requirements related to Restoration; R5 of the standard does require that the entity "shall demonstrate efforts to correct any identified Unresolved Maintenance Issues." Some examples of restoration (or correction of Unresolved Maintenance Issues) include, but are not limited to, replacement of capacitors in distance relays to bring them to working order; replacement of relays, or other Protection System components, to bring the Protection System to working order; upgrade of electromechanical or solid-state protective relays to microprocessor-based relays following the discovery of failed components. Restoration, as used in this context, is not to be confused with restoration rules as used in system operations. Maintenance activity necessarily includes both the detection of problems and the repairs needed to eliminate those problems. This standard does not identify all of the Protection System problems that must be detected and eliminated, rather it is the intent of this standard that an entity determines the necessary working order for their various devices, and keeps them in working order. If an equipment item is repaired or replaced, then the entity can restart the maintenance-time-interval-clock, if desired; however, the replacement of equipment does not remove any documentation requirements that would have been required to verify compliance with time-interval requirements. In other words, do not discard maintenance data that goes to verify your work.

The retention of documentation for new and/or replaced equipment is all about proving that the maintenance intervals had been in compliance. For example, a long-range plan of upgrades might lead an entity to ignore required maintenance; retaining the evidence of prior maintenance that existed before any retirements and upgrades proves compliance with the standard.

Please clarify what is meant by "…demonstrate efforts to correct an Unresolved Maintenance Issue…"; why not measure the completion of the corrective action?

Management of completion of the identified Unresolved Maintenance Issue is a complex topic that falls outside of the scope of this standard. There can be any number of supply, process and management problems that make setting repair deadlines impossible. The SDT specifically chose the phrase "demonstrate efforts to correct" (with guidance from NERC Staff) because of the concern that many more complex Unresolved Maintenance Issues might require greater than the remaining maintenance interval to resolve (and yet still be a "closed-end process"). For example, a problem might be identified on a VRLA battery during a six-month check. In instances such as one that requiring battery replacement as part of the long-term resolution, it is highly unlikely that the battery could be replaced in time to meet the six-calendar-month requirement for this maintenance activity. The SDT does not believe entities should be found in violation of a maintenance program requirement because of the inability to complete a remediation program within the original maintenance interval. The SDT does believe corrective actions should be timely, but concludes it would be impossible to postulate all possible remediation projects; and, therefore, impossible to specify bounding time frames for resolution of all possible Unresolved Maintenance Issues, or what documentation might be sufficient to provide proof that effective corrective action is being undertaken.

5. Time-Based Maintenance (TBM) Programs

Time-based maintenance is the process in which Protection System, Automatic Reclosing and Sudden Pressure Relaying Components are maintained or verified according to a time schedule. The scheduled program often calls for technicians to travel to the physical site and perform a functional test on Protection System components. However, some components of a TBM program may be conducted from a remote location - for example, tripping a circuit breaker by communicating a trip command to a microprocessor relay to determine if the entire Protection System tripping chain is able to operate the breaker. Similarly, all Protection System, and Sudden Pressure Relaying Components can have the ability to remotely conduct tests, either on-command or routinely; the running of these tests can extend the time interval between hands-on maintenance activities.

5.1 Maintenance Practices

Maintenance and testing programs often incorporate the following types of maintenance practices:

- TBM – time-based maintenance – externally prescribed maximum maintenance or testing intervals are applied for components or groups of components. The intervals may have been developed from prior experience or manufacturers' recommendations. The TBM verification interval is based on a variety of factors, including experience of the particular asset owner, collective experiences of several asset owners who are members of a country or regional council, etc. The maintenance intervals are fixed and may range in number of months or in years.

  TBM can include review of recent power system events near the particular terminal. Operating records may verify that some portion of the Protection System has operated correctly since the last test occurred. If specific protection scheme components have demonstrated correct performance within specifications, the maintenance test time clock can be reset for those components.

- PBM – Performance-Based Maintenance - intervals are established based on analytical or historical results of TBM failure rates on a statistically significant population of similar components. Some level of TBM is generally followed. Statistical analyses accompanied by adjustments to maintenance intervals are used to justify continued use of PBM-developed extended intervals when test failures or in-service failures occur infrequently.

- CBM – condition-based maintenance – continuously or frequently reported results from non-disruptive self-monitoring of components demonstrate operational status as those components remain in service. Whatever is verified by CBM does not require manual testing, but taking advantage of this requires precise technical focus on exactly what parts are included as part of the self-diagnostics. While the term "Condition-Based-Maintenance" (CBM) is no longer used within the standard itself, it is important to note that the concepts of CBM are a part of the standard (in the form of extended time intervals through status-monitoring). These extended time intervals are only allowed (in the absence of PBM) if the condition of the device is monitored (CBM). As a consequence of the "monitored-basis-time-intervals" existing within the standard, the explanatory

discussions within this Supplementary Reference concerned with CBM will remain in this reference and are discussed as CBM.

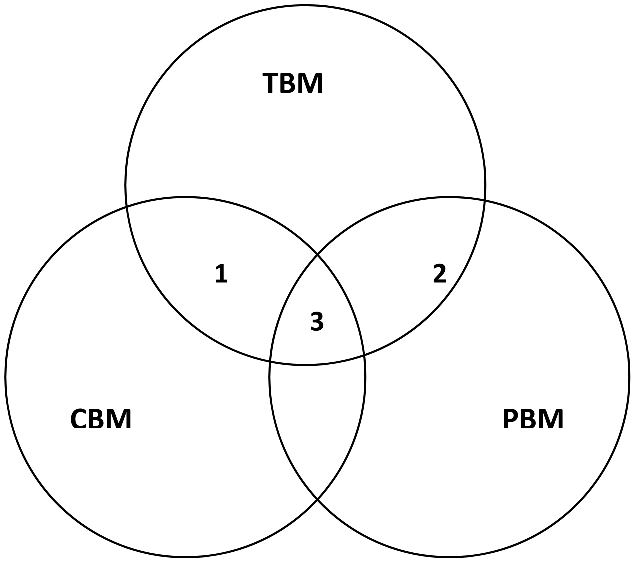
Microprocessor-based Protection System or Automatic Reclosing Components that perform continuous self-monitoring verify correct operation of most components within the device. Self-monitoring capabilities may include battery continuity, float voltages, unintentional grounds, the ac signal inputs to a relay, analog measuring circuits, processors and memory for measurement, protection, and data communications, trip circuit monitoring, and protection or data communications signals (and many, many more measurements). For those conditions, failure of a self-monitoring routine generates an alarm and may inhibit operation to avoid false trips. When internal components, such as critical output relay contacts, are not equipped with self-monitoring, they can be manually tested. The method of testing may be local or remote, or through inherent performance of the scheme during a system event.

The TBM is the overarching maintenance process of which the other types are subsets. Unlike TBM, PBM intervals are adjusted based on good or bad experiences. The CBM verification intervals can be hours, or even milliseconds between non-disruptive self-monitoring checks within or around components as they remain in service.

TBM, PBM, and CBM can be combined for individual components, or within a complete Protection System. The following diagram illustrates the relationship between various types of maintenance practices described in this section. In the Venn diagram, the overlapping regions show the relationship of TBM with PBM historical information and the inherent continuous monitoring offered through CBM.

This figure shows:

- Region 1: The TBM intervals that are increased based on known reported operational condition of individual components that are monitoring themselves.
- Region 2: The TBM intervals that are adjusted up or down based on results of analysis of maintenance history of statistically significant population of similar products that have been subject to TBM.
- Region 3: Optimal TBM intervals based on regions 1 and 2.



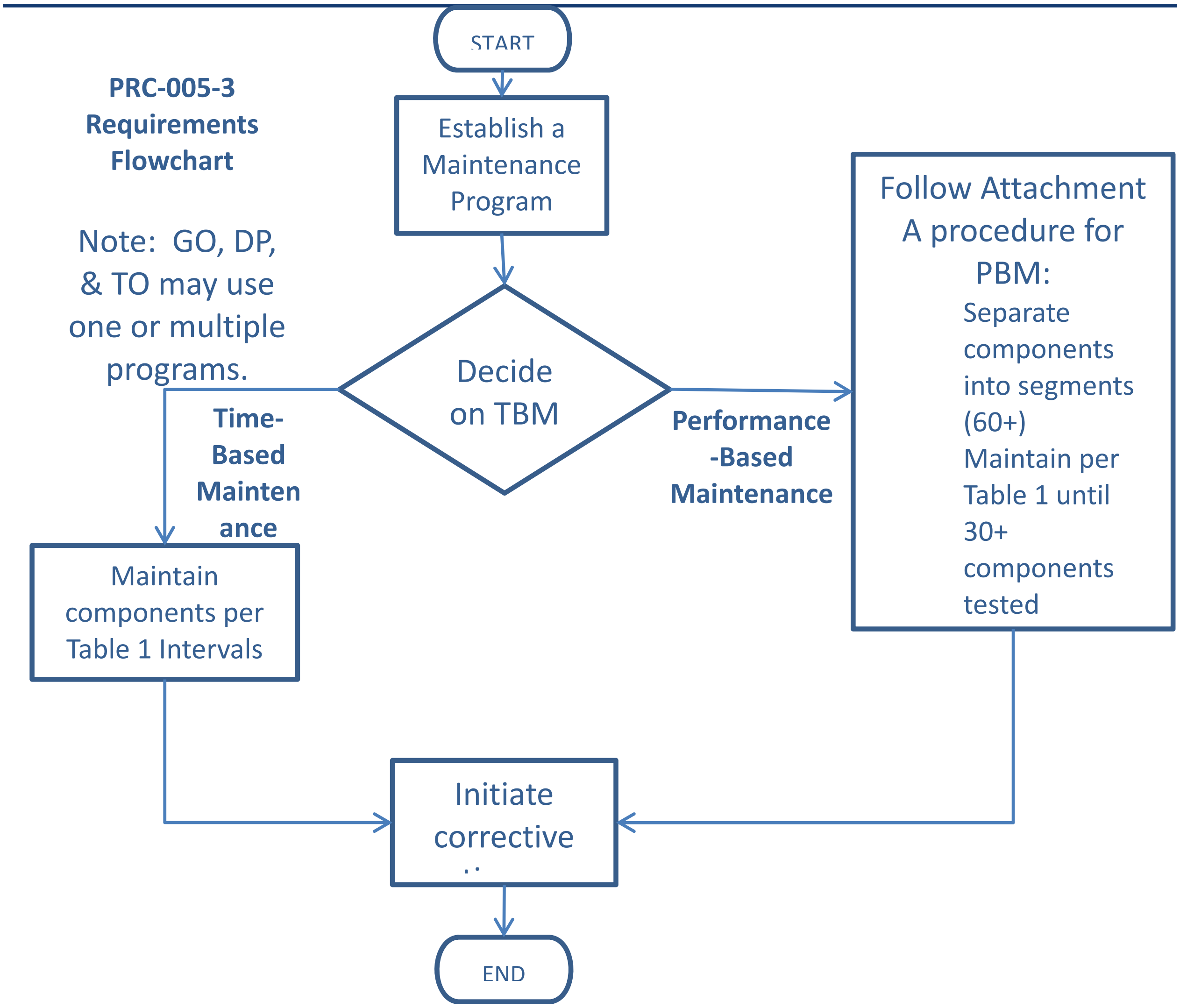
Relationship of time-based maintenance types

5.1.1 Frequently Asked Questions:

The standard seems very complicated, and is difficult to understand. Can it be simplified?

Because the standard is establishing parameters for condition-based Maintenance (R1) and Performance-Based Maintenance (R2), in addition to simple time-based Maintenance, it does appear to be complicated. At its simplest, an entity needs to ONLY perform time-based maintenance according to the unmonitored rows of the Tables. If an entity then wishes to take advantage of monitoring on its Protection System components and its available lengthened time intervals, then it may, as long as the component has the listed monitoring attributes. If an entity wishes to use historical performance of its Protection System components to perform Performance-Based Maintenance, then R2 applies.

Please see the following diagram, which provides a “flow chart” of the standard.



We have an electromechanical (unmonitored) relay that has a trip output to a lockout relay (unmonitored) which trips our transformer off-line by tripping the transformer's high-side and low-side circuit breakers. What testing must be done for this system?

This system is made up of components that are all unmonitored. Assuming a time-based Protection System Maintenance Program schedule (as opposed to a Performance-Based maintenance program), each component must be maintained per the most frequent hands-on activities listed in the Tables.

5.2 Extending Time-Based Maintenance

All maintenance is fundamentally time-based. Default time-based intervals are commonly established to assure proper functioning of each component of the Protection System, when data on the reliability of the components is not available other than observations from time-based maintenance. The following factors may influence the established default intervals:

- If continuous indication of the functional condition of a component is available (from relays or chargers or any self-monitoring device), then the intervals may be extended, or manual testing may be eliminated. This is referred to as condition-based maintenance or

CBM. CBM is valid only for precisely the components subject to monitoring. In the case of microprocessor-based relays, self-monitoring may not include automated diagnostics of every component within a microprocessor.

- Previous maintenance history for a group of components of a common type may indicate that the maintenance intervals can be extended, while still achieving the desired level of performance. This is referred to as Performance-Based Maintenance, or PBM. It is also sometimes referred to as reliability-centered maintenance, or RCM; but PBM is used in this document.
- Observed proper operation of a component may be regarded as a maintenance verification of the respective component or element in a microprocessor-based device. For such an observation, the maintenance interval may be reset only to the degree that can be verified by data available on the operation. For example, the trip of an electromechanical relay for a Fault verifies the trip contact and trip path, but only through the relays in series that actually operated; one operation of this relay cannot verify correct calibration.

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. The improper application of test signals may cause failure of a component. For example, in electromechanical overcurrent relays, test currents have been known to destroy convolution springs.

In addition, maintenance usually takes the component out of service, during which time it is not able to perform its function. Cutout switch failures, or failure to restore switch position, commonly lead to protection failures.

5.2.1 Frequently Asked Questions:

If I show the protective device out of service while it is being repaired, then can I add it back as a new protective device when it returns? If not, my relay testing history would show that I was out of compliance for the last maintenance cycle.

The maintenance and testing requirements (R5) (in essence) state "…shall demonstrate efforts to correct any identified Unresolved Maintenance Issues." The type of corrective activity is not stated; however it could include repairs or replacements.

Your documentation requirements will increase, of course, to demonstrate that your device tested bad and had corrective actions initiated. Your regional entity could very well ask for documentation showing status of your corrective actions.

6. Condition-Based Maintenance (CBM) Programs

Condition-based maintenance is the process of gathering and monitoring the information available from modern microprocessor-based relays and other intelligent electronic devices (IEDs) that monitor Protection System or Automatic Reclosing elements. These devices generate monitoring information during normal operation, and the information can be assessed at a convenient location remote from the substation. The information from these relays and IEDs is divided into two basic types:

1. Information can come from background self-monitoring processes, programmed by the manufacturer, or by the user in device logic settings. The results are presented by alarm contacts or points, front panel indications, and by data communications messages.
2. Information can come from event logs, captured files, and/or oscillographic records for Faults and Disturbances, metered values, and binary input status reports. Some of these are available on the device front panel display, but may be available via data communications ports. Large files of Fault information can only be retrieved via data communications. These results comprise a mass of data that must be further analyzed for evidence of the operational condition of the Protection System.

Using these two types of information, the user can develop an effective maintenance program carried out mostly from a central location remote from the substation. This approach offers the following advantages:

Non-invasive Maintenance: The system is kept in its normal operating state, without human intervention for checking. This reduces risk of damage, or risk of leaving the system in an inoperable state after a manual test. Experience has shown that keeping human hands away from equipment known to be working correctly enhances reliability.

Virtually Continuous Monitoring: CBM will report many hardware failure problems for repair within seconds or minutes of when they happen. This reduces the percentage of problems that are discovered through incorrect relaying performance. By contrast, a hardware failure discovered by TBM may have been there for much of the time interval between tests, and there is a good chance that some devices will show health problems by incorrect operation before being caught in the next test round. The frequent or continuous nature of CBM makes the effective verification interval far shorter than any required TBM maximum interval. To use the extended time intervals available through Condition Based Maintenance, simply look for the rows in the Tables that refer to monitored items.

6.1 Frequently Asked Questions:

My microprocessor relays and dc circuit alarms are contained on relay panels in a 24-hour attended control room. Does this qualify as an extended time interval condition-based (monitored) system?

Yes, provided the station attendant (plant operator, etc.) monitors the alarms and other indications (comparable to the monitoring attributes) and reports them within the given time limits that are stated in the criteria of the Tables.

When documenting the basis for inclusion of components into the appropriate levels of monitoring, as per Requirement R1 (Part 1.2) of the standard, is it necessary to provide this documentation about the device by listing of every component and the specific monitoring attributes of each device?

No. While maintaining this documentation on the device level would certainly be permissible, it is not necessary. Global statements can be made to document appropriate levels of monitoring for the entire population of a component type or portion thereof.

For example, it would be permissible to document the conclusion that all BES substation dc supply battery chargers are monitored by stating the following within the program description:

> "All substation dc supply battery chargers are considered monitored and subject to the rows for monitored equipment of Table 1-4 requirements, as all substation dc supply battery chargers are equipped with dc voltage alarms and ground detection alarms that are sent to the manned control center."

Similarly, it would be acceptable to use a combination of a global statement and a device-level list of exclusions. Example:

> "Except as noted below, all substation dc supply battery chargers are considered monitored and subject to the rows for monitored equipment of Table 1-4 requirements, as all substation dc supply battery chargers are equipped with dc voltage alarms and ground detection alarms that are sent to the manned control center. The dc supply battery chargers of Substation X, Substation Y, and Substation Z are considered unmonitored and subject to the rows for unmonitored equipment in Table 1-4 requirements, as they are not equipped with ground detection capability."

Regardless whether this documentation is provided by device listing of monitoring attributes, by global statements of the monitoring attributes of an entire population of component types, or by some combination of these methods, it should be noted that auditors may request supporting drawings or other documentation necessary to validate the inclusion of the device(s) within the appropriate level of monitoring. This supporting background information need not be maintained within the program document structure, but should be retrievable if requested by an auditor.

7. Time-Based Versus Condition-Based Maintenance

Time-based and condition-based (or monitored) maintenance programs are both acceptable, if implemented according to technically sound requirements. Practical programs can employ a *combination of time-based and condition-based maintenance.* The standard requirements introduce the concept of optionally using condition monitoring as a documented element of a maintenance program.

The Federal Energy Regulatory Commission (FERC), in its Order Number 693 Final Rule, dated March 16, 2007 (18 CFR Part 40, Docket No. RM06-16-000) on Mandatory Reliability Standards for the Bulk-Power System, directed NERC to submit a modification to PRC-005-1b that includes a requirement that maintenance and testing of a Protection System must be carried out within a maximum allowable interval that is appropriate to the type of the Protection System and its impact on the reliability of the Bulk Power System. Accordingly, this Supplementary Reference Paper refers to the specific maximum allowable intervals in PRC-005-4. The defined time limits allow for longer time intervals if the maintained component is monitored.

A key feature of condition-based monitoring is that it effectively reduces the time delay between the moment of a protection failure and time the Protection System or Automatic Reclosing owner knows about it, for the monitored segments of the Protection System. In some cases, the verification is practically continuous - the time interval between verifications is minutes or seconds. Thus, technically sound, condition-based verification, meets the verification requirements of the FERC order even more effectively than the strictly time-based tests of the same system components.

The result is that:

This NERC standard permits utilities to use a technically sound approach and to take advantage of remote monitoring, data analysis, and control capabilities of modern Protection System and Automatic Reclosing Components to reduce the need for periodic site visits and invasive testing of components by on-site technicians. This periodic testing must be conducted within the maximum time intervals specified in the Tables of PRC-005-4.

7.1 Frequently Asked Questions:

What is a Calendar Year?

Calendar Year - January 1 through December 31 of any year. As an example, if an event occurred on June 17, 2009 and is on a “One Calendar Year Interval,” the next event would have to occur on or before December 31, 2010.

Please provide an example of “4 Calendar Months”.

If a maintenance activity is described as being needed every four Calendar Months then it is performed in a (given) month and due again four months later. For example a battery bank is inspected in month number 1 then it is due again before the end of the month number5. And specifically consider that you perform your battery inspection on January 3, 2010 then it must be inspected again before the end of May. Another example could be that a four-month inspection

was performed in January is due in May, but if performed in March (instead of May) would still be due four months later therefore the activity is due again July. Basically every “four Calendar Months” means to add four months from the last time the activity was performed.

Please provide an example of the unmonitored versus other levels of monitoring available?

An unmonitored Protection System has no monitoring and alarm circuits on the Protection System components. A Protection System component that has monitoring attributes but no alarm output connected is considered to be unmonitored.

A monitored Protection System or an individual monitored component of a Protection System has monitoring and alarm circuits on the Protection System components. The alarm circuits must alert, within 24 hours, a location wherein corrective action can be initiated. This location might be, but is not limited to, an Operations Center, Dispatch Office, Maintenance Center or even a portable SCADA system.

There can be a combination of monitored and unmonitored Protection Systems within any given scheme, substation or plant; there can also be a combination of monitored and unmonitored components within any given Protection System.

Example #1: A combination of monitored and unmonitored components within a given Protection System might be:

- A microprocessor relay with an internal alarm connected to SCADA to alert 24-hr staffed operations center; it has internal self-diagnosis and alarming. (monitored)
- Instrumentation transformers, with no monitoring, connected as inputs to that relay. (unmonitored)
- A vented Lead-Acid battery with a low voltage alarm for the station dc supply voltage and an unintentional grounds detection alarm connected to SCADA. (monitoring varies)
- A circuit breaker with a trip coil, and the trip circuit is not monitored. (unmonitored)

Given the particular components and conditions, and using Table 1 and Table 2, the particular components have maximum activity intervals of:

<u>Every four calendar months</u>, inspect:

- Electrolyte level (station dc supply voltage and unintentional ground detection is being maintained more frequently by the monitoring system).

<u>Every 18 calendar months</u>, verify/inspect the following:

- Battery bank ohmic values to station battery baseline (if performance tests are not opted)
- Battery charger float voltage
- Battery rack integrity
- Cell condition of all individual battery cells (where visible)
- Battery continuity
- Battery terminal connection resistance

- Battery cell-to-cell resistance (where available to measure)

<u>Every six calendar years</u>, perform/verify the following:

- Battery performance test (if internal ohmic tests or other measurements indicative of battery performance are not opted)
- Verify that each trip coil is able to operate the circuit breaker, interrupting device, or mitigating device
- For electromechanical lock-out relays, electrical operation of electromechanical trip

<u>Every 12 calendar years</u>, verify the following:

- Microprocessor relay settings are as specified
- Operation of the microprocessor's relay inputs and outputs that are essential to proper functioning of the Protection System
- Acceptable measurement of power System input values seen by the microprocessor protective relay
- Verify that current and voltage signal values are provided to the protective relays
- Protection System component monitoring for the battery system signals are conveyed to a location where corrective action can be initiated
- The microprocessor relay alarm signals are conveyed to a location where corrective action can be initiated
- Verify all trip paths in the control circuitry associated with protective functions through the trip coil(s) of the circuit breakers or other interrupting devices
- Auxiliary outputs that are in the trip path shall be maintained as detailed in Table 1-5 of the standard under the 'Unmonitored Control Circuitry Associated with Protective Functions" section'
- Auxiliary outputs not in a trip path (i.e., annunciation or DME input) are not required, by this standard, to be checked

Example #2: A combination of monitored and unmonitored components within a given Protection System might be:

- A microprocessor relay with integral alarm that is not connected to SCADA. (unmonitored)
- Current and voltage signal values, with no monitoring, connected as inputs to that relay. (unmonitored)
- A vented lead-acid battery with a low voltage alarm for the station dc supply voltage and an unintentional grounds detection alarm connected to SCADA. (monitoring varies)
- A circuit breaker with a trip coil, with no circuits monitored. (unmonitored)

Given the particular components and conditions, and using the Table 1 (Maximum Allowable Testing Intervals and Maintenance Activities) and Table 2 (Alarming Paths and Monitoring), the particular components have maximum activity intervals of:

Every four calendar months, inspect:

- Electrolyte level (station dc supply voltage and unintentional ground detection is being maintained more frequently by the monitoring system)

Every 18 calendar months, verify/inspect the following:

- Battery bank trending of ohmic values or other measurements indicative of battery performance to station battery baseline (if performance tests are not opted)
- Battery charger float voltage
- Battery rack integrity
- Cell condition of all individual battery cells (where visible)
- Battery continuity
- Battery terminal connection resistance
- Battery cell-to-cell resistance (where available to measure)

Every six calendar years, verify/perform the following:

- Verify operation of the relay inputs and outputs that are essential to proper functioning of the Protection System
- Verify acceptable measurement of power system input values as seen by the relays
- Verify that each trip coil is able to operate the circuit breaker, interrupting device, or mitigating device
- For electromechanical lock-out relays, electrical operation of electromechanical trip
- Battery performance test (if internal ohmic tests are not opted)

Every 12 calendar years, verify the following:

- Current and voltage signal values are provided to the protective relays
- Protection System component monitoring for the battery system signals are conveyed to a location where corrective action can be initiated
- All trip paths in the control circuitry associated with protective functions through the trip coil(s) of the circuit breakers or other interrupting devices
- Auxiliary outputs that are in the trip path shall be maintained, as detailed in Table 1-5 of the standard under the Unmonitored Control Circuitry Associated with Protective Functions" section
- Auxiliary outputs not in a trip path (i.e., annunciation or DME input) are not required, by this standard, to be checked

Example #3: A combination of monitored and unmonitored components within a given Protection System might be:

- A microprocessor relay with alarm connected to SCADA to alert 24-hr staffed operations center; it has internal self-diagnosis and alarms. (monitored)
- Current and voltage signal values, with monitoring, connected as inputs to that relay (monitored)

- Vented Lead-Acid battery without any alarms connected to SCADA (unmonitored)
- Circuit breaker with a trip coil, with no circuits monitored (unmonitored)

Given the particular components, conditions, and using the Table 1 (Maximum Allowable Testing Intervals and Maintenance Activities) and Table 2 (Alarming Paths and Monitoring), the particular components shall have maximum activity intervals of:

Every four calendar months, verify/inspect the following:

- Station dc supply voltage
- For unintentional grounds
- Electrolyte level

Every 18 calendar months, verify/inspect the following:

- Battery bank trending of ohmic values or other measurements indicative of battery performance to station battery baseline (if performance tests are not opted)
- Battery charger float voltage
- Battery rack integrity
- Battery continuity
- Battery terminal connection resistance
- Battery cell-to-cell resistance (where available to measure)
- Condition of all individual battery cells (where visible)

Every six calendar years, perform/verify the following:

- Battery performance test (if internal ohmic tests or other measurements indicative of battery performance are not opted)
- Verify that each trip coil is able to operate the circuit breaker, interrupting device, or mitigating device
- For electromechanical lock-out relays, electrical operation of electromechanical trip

Every 12 calendar years, verify the following:

- The microprocessor relay alarm signals are conveyed to a location where corrective action can be taken
- Microprocessor relay settings are as specified
- Operation of the microprocessor’s relay inputs and outputs that are essential to proper functioning of the Protection System
- Acceptable measurement of power system input values seen by the microprocessor protective relay
- Verify all trip paths in the control circuitry associated with protective functions through the trip coil(s) of the circuit breakers or other interrupting devices

- Auxiliary outputs that are in the trip path shall be maintained, as detailed in Table 1-5 of the standard under the Unmonitored Control Circuitry Associated with Protective Functions section
- Auxiliary outputs not in a trip path (i.e. annunciation or DME input) are not required, by this standard, to be checked

Why do components have different maintenance activities and intervals if they are monitored?

The intent behind different activities and intervals for monitored equipment is to allow less frequent manual intervention when more information is known about the condition of Protection System components. Condition-Based Maintenance is a valuable asset to improve reliability.

Can all components in a Protection System be monitored?

No. For some components in a Protection System, monitoring will not be relevant. For example, a battery will always need some kind of inspection.

We have a 30-year-old oil circuit breaker with a red indicating lamp on the substation relay panel that is illuminated only if there is continuity through the breaker trip coil. There is no SCADA monitor or relay monitor of this trip coil. The line protection relay package that trips this circuit breaker is a microprocessor relay that has an integral alarm relay that will assert on a number of conditions that includes a loss of power to the relay. This alarm contact connects to our SCADA system and alerts our 24-hour operations center of relay trouble when the alarm contact closes. This microprocessor relay trips the circuit breaker only and does not monitor trip coil continuity or other things such as trip current. Are the components monitored or not? How often must I perform maintenance?

The protective relay is monitored and can be maintained every 12 years, or when an Unresolved Maintenance Issue arises. The control circuitry can be maintained every 12 years. The circuit breaker trip coil(s) has to be electrically operated at least once every six years.

What is a mitigating device?

A mitigating device is the device that acts to respond as directed by a Remedial Action System. It may be a breaker, valve, distributed control system, or any variety of other devices. This response may include tripping, closing, or other control actions.

8. Maximum Allowable Verification Intervals

The maximum allowable testing intervals and maintenance activities show how CBM with newer device types can reduce the need for many of the tests and site visits that older Protection System components require. As explained below, there are some sections of the Protection System that monitoring or data analysis may not verify. Verifying these sections of the Protection System or Automatic Reclosing requires some persistent TBM activity in the maintenance program. However, some of this TBM can be carried out remotely - for example, exercising a circuit breaker through the relay tripping circuits using the relay remote control capabilities can be used to verify function of one tripping path and proper trip coil operation, if there has been no Fault or routine operation to demonstrate performance of relay tripping circuits.

8.1 Maintenance Tests

Periodic maintenance testing is performed to ensure that the protection and control system is operating correctly after a time period of field installation. These tests may be used to ensure that individual components are still operating within acceptable performance parameters - this type of test is needed for components susceptible to degraded or changing characteristics due to aging and wear. Full system performance tests may be used to confirm that the total Protection System functions from measurement of power system values, to properly identifying Fault characteristics, to the operation of the interrupting devices.

8.1.1 Table of Maximum Allowable Verification Intervals

Table 1 (collectively known as Table 1, individually called out as Tables 1-1 through 1-5), Table 2, Table 3, Table 4-1 through Table 4-2, and Table 5 in the standard specify maximum allowable verification intervals for various generations of Protection Systems, Automatic Reclosing and Sudden Pressure Relaying and categories of equipment that comprise these systems. The right column indicates maintenance activities required for each category.

The types of components are illustrated in Figures 1 and 2 at the end of this paper. Figure 1 shows an example of telecommunications-assisted transmission Protection System comprising substation equipment at each terminal and a telecommunications channel for relaying between the two substations. Figure 2 shows an example of a generation Protection System. The various sub-systems of a Protection System that need to be verified are shown.

Non-distributed UFLS, UVLS, and RAS are additional categories of Table 1 that are not illustrated in these figures. Non-distributed UFLS, UVLS and RAS all use identical equipment as Protection Systems in the performance of their functions; and, therefore, have the same maintenance needs.

Distributed UFLS and UVLS Systems, which use local sensing on the distribution System and trip co-located non-BES interrupting devices, are addressed in Table 3 with reduced maintenance activities.

While it is easy to associate protective relays to multiple levels of monitoring, it is also true that most of the components that can make up a Protection System can also have technological advancements that place them into higher levels of monitoring.

To use the Maintenance Activities and Intervals Tables from PRC-005-4:

- First find the Table associated with your component. The tables are arranged in the order of mention in the definition of Protection System;
    - Table 1-1 is for protective relays,
    - Table 1-2 is for the associated communications systems,
    - Table 1-3 is for current and voltage sensing devices,
    - Table 1-4 is for station dc supply and
    - Table 1-5 is for control circuits.
    - Table 2, is for alarms; this was broken out to simplify the other tables.
    - Table 3 is for components which make-up distributed UFLS and UVLS Systems.
    - Table 4 is for Automatic Reclosing.
    - Table 5 is for Sudden Pressure Relaying.
- Next look within that table for your device and its degree of monitoring. The Tables have different hands-on maintenance activities prescribed depending upon the degree to which you monitor your equipment. Find the maintenance activity that applies to the monitoring level that you have on your piece of equipment.
- This Maintenance activity is the minimum maintenance activity that must be documented.
- If your Performance-Based Maintenance (PBM) plan requires <u>more activities,</u> then you must perform and document to this higher standard. (Note that this does not apply unless you utilize PBM.)
- After the maintenance activity is known, check the maximum maintenance interval; this time is the maximum time allowed between hands-on maintenance activity cycles of this component.
- If your Performance-Based Maintenance plan requires activities <u>more often</u> than the Tables maximum, then you must perform and document those activities to your more stringent standard. (Note that this does not apply unless you utilize PBM.)
- Any given component of a Protection System can be determined to have a degree of monitoring that may be different from another component within that same Protection System. For example, in a given Protection System it is possible for an entity to have a monitored protective relay and an unmonitored associated communications system; this combination would require hands-on maintenance activity on the relay at least once every 12 years and attention paid to the communications system as often as every four months.
- An entity does not have to utilize the extended time intervals made available by this use of condition-based monitoring. An easy choice to make is to simply utilize the unmonitored level of maintenance made available in each of the Tables. While the maintenance activities resulting from this choice would require more maintenance man-hours, the maintenance requirements may be simpler to document and the resulting maintenance plans may be easier to create.

For each Protection System Component, Table 1 shows maximum allowable testing intervals for the various degrees of monitoring. For each Automatic Reclosing Component, Table 4 shows maximum allowable testing intervals for the various degrees of monitoring. These degrees of monitoring, or levels, range from the legacy unmonitored through a system that is more comprehensively monitored.

It has been noted here that an entity may have a PSMP that is more stringent than PRC-005-4. There may be any number of reasons that an entity chooses a more stringent plan than the minimums prescribed within PRC-005-4, most notable of which is an entity using performance based maintenance methodology.

If an entity has a Performance-Based Maintenance program, then that plan must be followed, even if the plan proves to be more stringent than the minimums laid out in the Tables.

If an entity has a Time-Based Maintenance program and the PSMP is more stringent than PRC-005-4, they will only be audited in accordance with the standard (minimum maintenance activities and maximum maintenance intervals prescribed within Tables 1-1 through 1-5, Table 2, Table 3, Table 4-1 through 4-2, and Table 5).

8.1.2 Additional Notes for Tables 1-1 through 1-5, Table 3, and Table 4

1. For electromechanical relays, adjustment is required to bring measurement accuracy within the tolerance needed by the asset owner. Microprocessor relays with no remote monitoring of alarm contacts, etc., are unmonitored relays and need to be verified within the Table interval as other unmonitored relays but may be verified as functional by means other than testing by simulated inputs.

2. Microprocessor relays typically are specified by manufacturers as not requiring calibration, but acceptable measurement of power system input values must be verified (verification of the Analog to Digital [A/D] converters) within the Table intervals. The integrity of the digital inputs and outputs that are used as protective functions must be verified within the Table intervals.

3. Any Phasor Measurement Unit (PMU) function whose output is used in a Protection System or RAS (as opposed to a monitoring task) must be verified as a component in a Protection System.

4. In addition to verifying the circuitry that supplies dc to the Protection System, the owner must maintain the station dc supply. The most widespread station dc supply is the station battery and charger. Unlike most Protection System components, physical inspection of station batteries for signs of component failure, reduced performance, and degradation are required to ensure that the station battery is reliable enough to deliver dc power when required. IEEE Standards 450, 1188, and 1106 for vented lead-acid, valve-regulated lead-acid, and nickel-cadmium batteries, respectively (which are the most commonly used substation batteries on the NERC BES) have been developed as an important reference source of maintenance recommendations. The Protection System owner might want to follow the guidelines in the applicable IEEE recommended practices for battery maintenance and testing, especially if the battery in question is used for application requirements in addition to the protection and control demands covered under this standard. However, the Standard Drafting Team has tailored the battery maintenance and

testing guidelines in PRC-005-4 for the Protection System owner which are application specific for the BES Facilities. While the IEEE recommendations are all encompassing, PRC-005-4 is a more economical approach while addressing the reliability requirements of the BES.

5. Aggregated small entities might distribute the testing of the population of UFLS/UVLS systems, and large entities will usually maintain a portion of these systems in any given year. Additionally, if relatively small quantities of such systems do not perform properly, it will not affect the integrity of the overall program. Thus, these distributed systems have decreased requirements as compared to other Protection Systems.
6. Voltage & current sensing device circuit input connections to the Protection System relays can be verified by (but not limited to) comparison of measured values on live circuits or by using test currents and voltages on equipment out of service for maintenance. The verification process can be automated or manual. The values should be verified to be as expected (phase value and phase relationships are both equally important to verify).
7. "End-to-end test," as used in this Supplementary Reference, is any testing procedure that creates a remote input to the local communications-assisted trip scheme. While this can be interpreted as a GPS-type functional test, it is not limited to testing via GPS. Any remote scheme manipulation that can cause action at the local trip path can be used to functionally-test the dc control circuitry. A documented Real-time trip of any given trip path is acceptable in lieu of a functional trip test. It is possible, with sufficient monitoring, to be able to verify each and every parallel trip path that participated in any given dc control circuit trip. Or another possible solution is that a single trip path from a single monitored relay can be verified to be the trip path that successfully tripped during a Real-time operation. The variations are only limited by the degree of engineering and monitoring that an entity desires to pursue.
8. A/D verification may use relay front panel value displays, or values gathered via data communications. Groupings of other measurements (such as vector summation of bus feeder currents) can be used for comparison if calibration requirements assure acceptable measurement of power system input values.
9. Notes 1-8 attempt to describe some testing activities; they do not represent the only methods to achieve these activities, but rather some possible methods. Technological advances, ingenuity and/or industry accepted techniques can all be used to satisfy maintenance activity requirements; the standard is technology- and method-neutral in most cases.

8.1.3 Frequently Asked Questions:

What is meant by "Verify that settings are as specified" maintenance activity in Table 1-1?

Verification of settings is an activity directed mostly towards microprocessor- based relays. For relay maintenance departments that choose to test microprocessor-based relays in the same manner as electromechanical relays are tested, the testing process sometimes requires that some specific functions be disabled. Later tests might enable the functions previously disabled, but perhaps still other functions or logic statements were then masked out. It is imperative that, when the relay is placed into service, the settings in the relay be the settings that were intended to be in that relay or as the standard states "…settings are as specified."

Many of the microprocessor- based relays available today have software tools which provide this functionality and generate reports for this purpose.

For evidence or documentation of this requirement, a simple recorded acknowledgement that the settings were checked to be as specified is sufficient.

The drafting team was careful not to require "…that the relay settings be correct…" because it was believed that this might then place a burden of proof that the specified settings would result in the correct intended operation of the interrupting device. While that is a noble intention, the measurable proof of such a requirement is immense. The intent is that settings of the component be as specified at the conclusion of maintenance activities, whether those settings may have "drifted" since the prior maintenance or whether changes were made as part of the testing process.

Are electromechanical relays included in the "Verify that settings are as specified" maintenance activity in Table 1-1?

Verification of settings is an activity directed towards the application of protection related functions of microprocessor based relays. Electromechanical relays require calibration verification by voltage and/or current injection; and, thus, the settings are verified during calibration activity. In the example of a time-overcurrent relay, a minor deviation in time dial, versus the settings, may be acceptable, as long as the relay calibration is within accepted tolerances at the injected current amplitudes. A major deviation may require further investigation, as it could indicate a problem with the relay or an incorrect relay style for the application.

The verification of phase current and voltage measurements by comparison to other quantities seems reasonable. How, though, can I verify residual or neutral currents, or 3V0 voltages, by comparison, when my system is closely balanced?

Since these inputs are verified at commissioning, maintenance verification requires ensuring that phase quantities are as expected and that 3IO and 3VO quantities appear equal to or close to 0.

These quantities also may be verified by use of oscillographic records for connected microprocessor relays as recorded during system Disturbances. Such records may compare to similar values recorded at other locations by other microprocessor relays for the same event, or compared to expected values (from short circuit studies) for known Fault locations.

What does this Standard require for testing an auxiliary tripping relay?

Table 1 and Table 3 requires that a trip test must verify that the auxiliary tripping relay(s) and/or lockout relay(s) which are directly in a trip path from the protective relay to the interrupting device trip coil operate(s) electrically. Auxiliary outputs not in a trip path (i.e. annunciation or DME input) are not required, by this standard, to be checked.

Do I have to perform a full end-to-end test of a Remedial Action System?

No. All portions of the -RAS need to be maintained, and the portions must overlap, but the overall RAS does not need to have a single end-to-end test. In other words it may be tested in piecemeal fashion provided all of the pieces are verified.

What about RAS interfaces between different entities or owners?

As in all of the Protection System requirements, RAS segments can be tested individually, thus minimizing the need to accommodate complex maintenance schedules.

What do I have to do if I am using a phasor measurement unit (PMU) as part of a Protection System or Remedial Action System?

Any Phasor Measurement Unit (PMU) function whose output is used in a Protection System or Remedial Action System (as opposed to a monitoring task) must be verified as a component in a Protection System.

How do I maintain a Remedial Action System or relay sensing for non-distributed UFLS or UVLS Systems?

Since components of the RAS, UFLS and UVLS are the same types of components as those in Protection Systems, then these components should be maintained like similar components used for other Protection System functions. In many cases the devices for RAS, UFLS and UVLS are also used for other protective functions. The same maintenance activities apply with the exception that distributed systems (UFLS and UVLS) have fewer dc supply and control circuitry maintenance activity requirements.

For the testing of the output action, verification may be by breaker tripping, but may be verified in overlapping segments. For example, an RAS that trips a remote circuit breaker might be tested by testing the various parts of the scheme in overlapping segments. Another method is to document the Real-time tripping of an RAS scheme should that occur. Forced trip tests of circuit breakers (etc.) that are a part of distributed UFLS or UVLS schemes are not required.

The established maximum allowable intervals do not align well with the scheduled outages for my power plant. Can I extend the maintenance to the next scheduled outage following the established maximum interval?

No. You must complete your maintenance within the established maximum allowable intervals in order to be compliant. You will need to schedule your maintenance during available outages to complete your maintenance as required, even if it means that you may do protective relay maintenance more frequently than the maximum allowable intervals. The maintenance intervals were selected with typical plant outages, among other things, in mind.

If I am unable to complete the maintenance, as required, due to a major natural disaster (hurricane, earthquake, etc.), how will this affect my compliance with this standard?

The Sanction Guidelines of the North American Electric Reliability Corporation, effective January 15, 2008, provides that the Compliance Monitor will consider extenuating circumstances when considering any sanctions.

What if my observed testing results show a high incidence of out-of-tolerance relays; or, even worse, I am experiencing numerous relay Misoperations due to the relays being out-of-tolerance?

The established maximum time intervals are mandatory only as a not-to-exceed limitation. The establishment of a maximum is measurable. But any entity can choose to test some or all of their Protection System components more frequently (or to express it differently, exceed the minimum requirements of the standard). Particularly if you find that the maximum intervals in the standard do not achieve your expected level of performance, it is understandable that you

would maintain the related equipment more frequently. A high incidence of relay Misoperations is in no one's best interest.

We believe that the four-month interval between inspections is unneccessary. Why can we not perform these inspections twice per year?

The Standard Drafting Team, through the comment process, has discovered that routine monthly inspections are not the norm. To align routine station inspections with other important inspections, the four-month interval was chosen. In lieu of station visits, many activities can be accomplished with automated monitoring and alarming.

Our maintenance plan calls for us to perform routine protective relay tests every 3 years. If we are unable to achieve this schedule, but we are able to complete the procedures in less than the maximum time interval ,then are we in or out of compliance?

According to R3, if you have a time-based maintenance program, then you will be in violation of the standard only if you exceed the maximum maintenance intervals prescribed in the Tables. According to R4, if your device in question is part of a Performance-Based Maintenance program, then you will be in violation of the standard if you fail to meet your PSMP, even if you do not exceed the maximum maintenance intervals prescribed in the Tables. The intervals in the Tables are associated with TBM and CBM; Attachment A is associated with PBM.

Please provide a sample list of devices or systems that must be verified in a generator, generator step-up transformer, generator connected station service or generator connected excitation transformer to meet the requirements of this maintenance standard.

Examples of typical devices and systems that may directly trip the generator, or trip through a lockout relay, may include, but are not necessarily limited to:

- Fault protective functions, including distance functions, voltage-restrained overcurrent functions, or voltage-controlled overcurrent functions
- Loss-of-field relays
- Volts-per-hertz relays
- Negative sequence overcurrent relays
- Over voltage and under voltage protection relays
- Stator-ground relays
- Communications-based Protection Systems such as transfer-trip systems
- Generator differential relays
- Reverse power relays
- Frequency relays
- Out-of-step relays
- Inadvertent energization protection

- Breaker failure protection

For generator step-up, generator-connected station service transformers, or generator connected excitation transformers, operation of any of the following associated protective relays frequently would result in a trip of the generating unit; and, as such, would be included in the program:

- Transformer differential relays
- Neutral overcurrent relay
- Phase overcurrent relays

Relays which trip breakers serving station auxiliary Loads such as pumps, fans, or fuel handling equipment, etc., need not be included in the program, even if the loss of the those Loads could result in a trip of the generating unit. Furthermore, relays which provide protection to secondary unit substation (SUS) or low switchgear transformers and relays protecting other downstream plant electrical distribution system components are not included in the scope of this program, even if a trip of these devices might eventually result in a trip of the generating unit. For example, a thermal overcurrent trip on the motor of a coal-conveyor belt could eventually lead to the tripping of the generator, but it does not cause the trip.

In the case where a plant does not have a generator connected station service transformer such that it is normally fed from a system connected station service transformer, is it still the drafting team's intent to exclude the Protection Systems for these system connected auxiliary transformers from scope even when the loss of the normal (system connected) station service transformer will result in a trip of a BES generating Facility?

The SDT does not intend that the system-connected station service transformers be included in the Applicability. The generator-connected station service transformers and generator connected excitation transformers are often connected to the generator bus directly without an interposing breaker; thus, the Protection Systems on these transformers will trip the generator as discussed in 4.2.5.1.

What is meant by "verify operation of the relay inputs and outputs that are essential to proper functioning of the Protection System?"

Any input or output (of the relay) that "affects the tripping" of the breaker is included in the scope of I/O of the relay to be verified. By "affects the tripping," one needs to realize that sometimes there are more inputs and outputs than simply the output to the trip coil. Many important protective functions include things like breaker fail initiation, zone timer initiation and sometimes even 52a/b contact inputs are needed for a protective relay to correctly operate.

Each input should be "picked up" or "turned on and off" and verified as changing state by the microprocessor of the relay. Each output should be "operated" or "closed and opened" from the microprocessor of the relay and the output should be verified to change state on the output terminals of the relay. One possible method of testing inputs of these relays is to "jumper" the needed dc voltage to the input and verify that the relay registered the change of state.

Electromechanical lock-out relays (86) (used to convey the tripping current to the trip coils) need to be electrically operated to prove the capability of the device to change state. These tests need to be accomplished at least every six years, unless PBM methodology is applied.

The contacts on the 86 or auxiliary tripping relays (94) that change state to pass on the trip current to a breaker trip coil need only be checked every 12 years with the control circuitry.

What is the difference between a distributed UFLS/UVLS and a non-distributed UFLS/UVLS scheme?

A distributed UFLS or UVLS scheme contains individual relays which make independent Load shed decisions based on applied settings and localized voltage and/or current inputs. A distributed scheme may involve an enable/disable contact in the scheme and still be considered a distributed scheme. A non-distributed UFLS or UVLS scheme involves a system where there is some type of centralized measurement and Load shed decision being made. A non-distributed UFLS/UVLS scheme is considered similar to an RAS scheme and falls under Table 1 for maintenance activities and intervals.

8.2 Retention of Records

PRC-005-1 describes a reporting or auditing cycle of one year and retention of records for three years. However, with a three-year retention cycle, the records of verification for a Protection System might be discarded before the next verification, leaving no record of what was done if a Misoperation or failure is to be analyzed.

PRC-005-4 corrects this by requiring:

The Transmission Owner, Generator Owner, and Distribution Provider shall each keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

For Requirement R1, the Transmission Owner, Generator Owner, and Distribution Provider shall each keep its current dated Protection System Maintenance Program, as well as any superseded versions since the preceding compliance audit, including the documentation that specifies the type of maintenance program applied for each Protection System, Automatic Reclosing, or Sudden Pressure Relaying Component Type.

For Requirement R2, Requirement R3, and Requirement R4, in cases where the interval of the maintenance activity is longer than the audit cycle, the Transmission Owner, Generator Owner, and Distribution Provider shall each keep documentation of the most recent performance of that maintenance activity for the Protection System, Automatic Reclosing, or Sudden Pressure Relaying Component. In cases where the interval of the maintenance activity is shorter than the audit cycle, documentation of all performances (in accordance with the tables) of that maintenance activity for the Protection System, Automatic Reclosing, or Sudden Pressure Relaying Component since the previous scheduled audit date shall be retained.

For Requirement R5 the Transmission Owner, Generator Owner, and Distribution Provider shall each keep documentation of Unresolved Maintenance Issues identified by the entity since the last audit, including all that were resolved since the last audit.

This requirement assures that the documentation shows that the interval between maintenance cycles correctly meets the maintenance interval limits. The requirement is actually alerting the industry to documentation requirements already implemented by audit teams. Evidence of compliance bookending the interval shows interval accomplished instead of proving only your planned interval.

The SDT is aware that, in some cases, the retention period could be relatively long. But, the retention of documents simply helps to demonstrate compliance.

8.2.1 Frequently Asked Questions:

Please clarify the data retention requirements.

The data retention requirements are intended to allow the availability of maintenance records to demonstrate that the time intervals in your maintenance plan were upheld.

Maximum Maintenance Interval	Data Retention Period
4 Months, 6 Months,18 Months, or 3 Years	All activities since previous audit
6 Years	All activities since previous audit(assuming a 6 year audit cycle) or most recent performance(assuming 3 year audit cycle), whichever is longer
12 Year	All activities from the most recent performance

If an entity prefers to utilize Performance-Based Maintenance, then statistical data may well be retained for extended periods to assist with future adjustments in time intervals.

If an equipment item is replaced, then the entity can restart the maintenance-time-interval-clock if desired; however, the replacement of equipment does not remove any documentation requirements that would have been required to verify compliance with time-interval requirements. In other words, do not discard maintenance data that goes to verify your work.

The retention of documentation for new and/or replaced equipment is all about proving that the maintenance intervals had been in compliance. For example, a long-range plan of upgrades might lead an entity to ignore required maintenance; retaining the evidence of prior maintenance that existed before any retirements and upgrades proves compliance with the standard.

What does this Maintenance Standard say about commissioning? Is it necessary to have documentation in your maintenance history of the completion of commission testing?

This standard does not establish requirements for commission testing. Commission testing includes all testing activities necessary to conclude that a Facility has been built in accordance with design. While a thorough commission testing program would include, either directly or indirectly, the verification of all those Protection System attributes addressed by the maintenance activities specified in the Tables of PRC-005-4, verification of the adequacy of initial installation necessitates the performance of testing and inspections that go well beyond these routine maintenance activities. For example, commission testing might set baselines for future tests; perform acceptance tests and/or warranty tests; utilize testing methods that are not generally done routinely like staged-Fault-tests.

However, many of the Protection System attributes which are verified during commission testing are not subject to age related or service related degradation, and need not be re-verified within an ongoing maintenance program. Example – it is not necessary to re-verify correct terminal strip wiring on an ongoing basis.

PRC-005-4 assumes that thorough commission testing was performed prior to a Protection System being placed in service. PRC-005-4 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.

It should be noted that commission testing frequently is performed by a different organization than that which is responsible for the ongoing maintenance of the Protection System. Furthermore, the commission testing activities will not necessarily correlate directly with the maintenance activities required by the standard. As such, it is very likely that commission testing records will deviate significantly from maintenance records in both form and content; and, therefore, it is not necessary to maintain commission testing records within the maintenance program documentation.

Notwithstanding the differences in records, an entity would be wise to retain commissioning records to show a maintenance start date. (See below). An entity that requires that their commissioning tests have, at a minimum, the requirements of PRC-005-4 would help that entity prove time interval maximums by setting the initial time clock.

How do you determine the initial due date for maintenance?

The initial due date for maintenance should be based upon when a Protection System was tested. Alternatively, an entity may choose to use the date of completion of the commission testing of the Protection System component and the system was placed into service as the starting point in determining its first maintenance due dates. Whichever method is chosen, for newly installed Protection Systems the components should not be placed into service until minimum maintenance activities have taken place.

It is conceivable that there can be a (substantial) difference in time between the date of testing, as compared to the date placed into service. The use of the "Calendar Year" language can help determine the next due date without too much concern about being non-compliant for missing test dates by a small amount (provided your dates are not already at the end of a year). However, if there is a substantial amount of time difference between testing and in-service dates, then the testing date should be followed because it is the degradation of components that is the concern. While accuracy fluctuations may decrease when components are not energized, there are cases when degradation can take place, even though the device is not energized. Minimizing the time between commissioning tests and in-service dates will help.

If I miss two battery inspections four times out of 100 Protection System components on my transmission system, does that count as 2% or 8% when counting Violation Severity Level (VSL) for R3?

The entity failed to complete its scheduled program on two of its 100 Protection System components, which would equate to 2% for application to the VSL Table for Requirement R3.

This VSL is written to compare missed components to total components. In this case two components out of 100 were missed, or 2%.

How do I achieve a "grace period" without being out of compliance?

The objective here is to create a time extension within your own PSMP that still does not violate the maximum time intervals stated in the standard. Remember that the maximum time intervals listed in the Tables cannot be extended.

For the purposes of this example, concentrating on just unmonitored protective relays – Table 1-1 specifies a maximum time interval (between the mandated maintenance activities) of six calendar years. Your plan must ensure that your unmonitored relays are tested at least once every six calendar years. You could, within your PSMP, require that your unmonitored relays be tested every four calendar years, with a maximum allowable time extension of 18 calendar months. This allows an entity to have deadlines set for the auto-generation of work orders, but still has the flexibility in scheduling complex work schedules. This also allows for that 18 calendar months to act as a buffer, in effect a grace period within your PSMP, in the event of unforeseen events. You will note that this example of a maintenance plan interval has a planned time of four years; it also has a built-in time extension allowed within the PSMP, and yet does not exceed the maximum time interval allowed by the standard. So while there are no time extensions allowed beyond the standard, an entity can still have substantial flexibility to maintain their Protection System components.

8.3 Basis for Table 1 Intervals

When developing the original *Protection System Maintenance – A Technical Reference* in 2007, the SPCTF collected all available data from Regional Entities (REs) on time intervals recommended for maintenance and test programs. The recommendations vary widely in categorization of relays, defined maintenance actions, and time intervals, precluding development of intervals by averaging. The SPCTF also reviewed the 2005 Report [2] of the IEEE Power System Relaying Committee Working Group I-17 (Transmission Relay System Performance Comparison). Review of the I-17 report shows data from a small number of utilities, with no company identification or means of investigating the significance of particular results.

To develop a solid current base of practice, the SPCTF surveyed its members regarding their maintenance intervals for electromechanical and microprocessor relays, and asked the members to also provide definitively-known data for other entities. The survey represented 470 GW of peak Load, or 4% of the NERC peak Load. Maintenance interval averages were compiled by weighting reported intervals according to the size (based on peak Load) of the reporting utility. Thus, the averages more accurately represent practices for the large populations of Protection Systems used across the NERC regions.

The results of this survey with weighted averaging indicate maintenance intervals of five years for electromechanical or solid state relays, and seven years for unmonitored microprocessor relays.

A number of utilities have extended maintenance intervals for microprocessor relays beyond seven years, based on favorable experience with the particular products they have installed. To provide a technical basis for such extension, the SPCTF authors developed a recommendation of 10 years using the Markov modeling approach from [1], as summarized in Section 8.4. The results of this modeling depend on the completeness of self-testing or monitoring. Accordingly, this extended interval is allowed by Table 1, only when such relays are monitored as specified in the attributes of monitoring contained in Tables 1-1 through 1-5 and Table 2. Monitoring is capable of reporting Protection System health issues that are likely to affect performance within the 10 year time interval between verifications.

It is important to note that, according to modeling results, Protection System availability barely changes as the maintenance interval is varied below the 10-year mark. Thus, reducing the maintenance interval does not improve Protection System availability. With the assumptions of the model regarding how maintenance is carried out, reducing the maintenance interval actually degrades Protection System availability.

8.4 Basis for Extended Maintenance Intervals for Microprocessor Relays

Table 1 allows maximum verification intervals that are extended based on monitoring level. The industry has experience with self-monitoring microprocessor relays that leads to the Table 1 value for a monitored relay, as explained in Section 8.3. To develop a basis for the maximum interval for monitored relays in their *Protection System Maintenance – A Technical Reference*, the SPCTF used the methodology of Reference [1], which specifically addresses optimum routine maintenance intervals. The Markov modeling approach of [1] is judged to be valid for the design and typical failure modes of microprocessor relays.

The SPCTF authors ran test cases of the Markov model to calculate two key probability measures:

- Relay Unavailability - the probability that the relay is out of service due to failure or maintenance activity while the power system Element to be protected is in service.
- Abnormal Unavailability - the probability that the relay is out of service due to failure or maintenance activity when a Fault occurs, leading to failure to operate for the Fault.

The parameter in the Markov model that defines self-monitoring capability is ST (for self-test). ST = 0 if there is no self-monitoring; ST = 1 for full monitoring. Practical ST values are estimated to range from .75 to .95. The SPCTF simulation runs used constants in the Markov model that were the same as those used in [1] with the following exceptions:

Sn, Normal tripping operations per hour = 21600 (reciprocal of normal Fault clearing time of 10 cycles)

Sb, Backup tripping operations per hour = 4320 (reciprocal of backup Fault clearing time of 50 cycles)

Rc, Protected component repairs per hour = 0.125 (8 hours to restore the power system)

Rt, Relay routine tests per hour = 0.125 (8 hours to test a Protection System)

Rr, Relay repairs per hour = 0.08333 (12 hours to complete a Protection System repair after failure)

Experimental runs of the model showed low sensitivity of optimum maintenance interval to these parameter adjustments.

The resulting curves for relay unavailability and abnormal unavailability versus maintenance interval showed a broad minimum (optimum maintenance interval) in the vicinity of 10 years – the curve is flat, with no significant change in either unavailability value over the range of 9, 10, or 11 years. This was true even for a relay mean time between Failures (MTBF) of 50 years, much lower than MTBF values typically published for these relays. Also, the Markov modeling indicates that both the relay unavailability and abnormal unavailability actually become higher with more frequent testing. This shows that the time spent on these more frequent tests yields no failure discoveries that approach the negative impact of removing the relays from service and running the tests.

The PSMT SDT discussed the practical need for “time-interval extensions” or “grace periods” to allow for scheduling problems that resulted from any number of business contingencies. The time interval discussions also focused on the need to reflect industry norms surrounding Generator outage frequencies. Finally, it was again noted that FERC Order 693 demanded maximum time intervals. “Maximum time intervals” by their very term negates any “time-interval extension” or “grace periods.” To recognize the need to follow industry norms on Generator outage frequencies and accommodate a form of time-interval extension, while still following FERC Order 693, the Standard Drafting Team arrived at a six-year interval for the electromechanical relay, instead of the five-year interval arrived at by the SPCTF. The PSMT SDT has followed the FERC directive for a *maximum* time interval and has determined that no extensions will be allowed. Six years has been set for the maximum time interval between manual maintenance activities. This maximum time interval also works well for maintenance cycles that have been in use in generator plants for decades.

For monitored relays, the PSMT SDT notes that the SPCTF called for 10 years as the interval between maintenance activities. This 10-year interval was chosen, even though there was “…no significant change in unavailability value over the range of 9, 10, or 11 years. This was true even for a relay Mean Time between Failures (MTBF) of 50 years…” The Standard Drafting Team again sought to align maintenance activities with known successful practices and outage schedules. The Standard does not allow extensions on any component of the Protection System; thus, the maximum allowed interval for these components has been set to 12 years. Twelve years also fits well into the traditional maintenance cycles of both substations and generator plants.

Also of note is the Table’s use of the term “Calendar” in the column for “Maximum Maintenance Interval.” The PSMT SDT deemed it necessary to include the term “Calendar” to facilitate annual maintenance planning, scheduling and implementation. This need is the result of known occurrences of system requirements that could cause maintenance schedules to be missed by a few days or weeks. The PSMT SDT chose the term “Calendar” to preclude the need to have schedules be met to the day. An electromechanical protective relay that is maintained in year number one need not be revisited until six years later (year number seven). For example, a relay was maintained April 10, 2008; maintenance would need to be completed no later than December 31, 2014.

Though not a requirement of this standard, to stay in line with many Compliance Enforcement Agencies audit processes an entity should define, within their own PSMP, the entity’s use of terms like annual, calendar year, etc. Then, once this is within the PSMP, the entity should abide by their chosen language.

9. Performance-Based Maintenance Process

In lieu of using the Table 1 intervals, a Performance-Based Maintenance process may be used to establish maintenance intervals (*PRC-005 Attachment A Criteria for a Performance-Based Protection System Maintenance Program*). A Performance-Based Maintenance process may justify longer maintenance intervals, or require shorter intervals relative to Table 1. In order to use a Performance-Based Maintenance process, the documented maintenance program must include records of repairs, adjustments, and corrections to covered Protection Systems in order to provide historical justification for intervals, other than those established in Table 1. Furthermore, the asset owner must regularly analyze these records of corrective actions to develop a ranking of causes. Recurrent problems are to be highlighted, and remedial action plans are to be documented to mitigate or eliminate recurrent problems.

Entities with Performance-Based Maintenance track performance of Protection Systems, demonstrate how they analyze findings of performance failures and aberrations, and implement continuous improvement actions. Since no maintenance program can ever guarantee that no malfunction can possibly occur, documentation of a Performance-Based Maintenance program would serve the utility well in explaining to regulators and the public a Misoperation leading to a major System outage event.

A Performance-Based Maintenance program requires auditing processes like those included in widely used industrial quality systems (such as ***ISO 9001-2000, Quality Management Systems — Requirements;*** or applicable parts of the NIST Baldridge National Quality Program). The audits periodically evaluate:

- The completeness of the documented maintenance process
- Organizational knowledge of and adherence to the process
- Performance metrics and documentation of results
- Remediation of issues
- Demonstration of continuous improvement.

In order to opt into a Performance-Based Maintenance (PBM) program, the asset owner must first sort the various Components into population segments. Any population segment must be comprised of at least 60 individual units; if any asset owner opts for PBM, but does not own 60 units to comprise a population, then that asset owner may combine data from other asset owners until the needed 60 units is aggregated. Each population segment must be composed of a grouping of Components of a consistent design standard or particular model or type from a single manufacturer and subjected to similar environmental factors. For example: One segment cannot be comprised of both GE & Westinghouse electro-mechanical lock-out relays; likewise, one segment cannot be comprised of 60 GE lock-out relays, 30 of which are in a dirty environment, and the remaining 30 from a clean environment. This PBM process cannot be applied to batteries, but can be applied to all other Components, including (but not limited to) specific battery chargers, instrument transformers, trip coils and/or control circuitry (etc.).

9.1 Minimum Sample Size

Large Sample Size

An assumption that needs to be made when choosing a sample size is "the sampling distribution of the sample mean can be approximated by a normal probability distribution." The Central Limit Theorem states: "In selecting simple random samples of size *n* from a population, the sampling distribution of the sample mean *x* can be approximated by a normal probability distribution as the sample size becomes large." (Essentials of Statistics for Business and Economics, Anderson, Sweeney, Williams, 2003.)

To use the Central Limit Theorem in statistics, the population size should be large. The references below are supplied to help define what is large.

> "… whenever we are using a large simple random sample (rule of thumb: n>=30), the central limit theorem enables us to conclude that the sampling distribution of the sample mean can be approximated by a normal distribution." (Essentials of Statistics for Business and Economics, Anderson, Sweeney, Williams, 2003.)
>
> "If samples of size n, when n>=30, are drawn from any population with a mean *u* and a standard deviation σ, the sampling distribution of sample means approximates a normal distribution. The greater the sample size, the better the approximation." (Elementary Statistics - Picturing the World, Larson, Farber, 2003.)
>
> "The sample size is large (generally n>=30)… (Introduction to Statistics and Data Analysis - Second Edition, Peck, Olson, Devore, 2005.)
>
> "… the normal is often used as an approximation to the *t* distribution in a test of a null hypothesis about the mean of a normally distributed population when the population variance is estimated from a relatively large sample. A sample size exceeding 30 is often given as a minimal size in this connection." (Statistical Analysis for Business Decisions, Peters, Summers, 1968.)

Error of Distribution Formula

Beyond the large sample size discussion above, a sample size requirement can be estimated using the bound on the Error of Distribution Formula when the expected result is of a "Pass/Fail" format and will be between 0 and 1.0.

The Error of Distribution Formula is:

$$B = z\sqrt{\frac{\pi(1-\pi)}{n}}$$

Where:

B = bound on the error of distribution (allowable error)

z = standard error

π = expected failure rate

n = sample size required

Solving for n provides:

$$n = \pi(1-\pi)\left(\frac{z}{B}\right)^2$$

Minimum Population Size to use Performance-Based Program

One entity's population of components should be large enough to represent a sizeable sample of a vendor's overall population of manufactured devices. For this reason, the following assumptions are made:

B = 5%

z = 1.96 (This equates to a 95% confidence level)

π = 4%

Using the equation above, n=59.0.

Minimum Sample Size to evaluate Performance-Based Program

The number of components that should be included in a sample size for evaluation of the appropriate testing interval can be smaller because a lower confidence level is acceptable since the sample testing is repeated or updated annually. For this reason, the following assumptions are made:

B = 5%

z = 1.44 (85% confidence level)

π = 4%

Using the equation above, n=31.8.

Recommendation

Based on the above discussion, a sample size should be at least 30 to allow use of the equation mentioned. Using this and the results of the equation, the following numbers are recommended (and required within the standard):

Minimum Population Size to use Performance-Based Maintenance Program = 60

Minimum Sample Size to evaluate Performance-Based Program = 30.

Once the population segment is defined, then maintenance must begin within the intervals as outlined for the device described in the Tables 1-1 through 1-5. Time intervals can be lengthened provided the last year's worth of components tested (or the last 30 units maintained, whichever is more) had fewer than 4% Countable Events. It is notable that 4% is specifically chosen because an entity with a small population (30 units) would have to adjust its time intervals between maintenance if more than one Countable Event was found to have occurred during the last analysis period. A smaller percentage would require that entity to adjust the time interval between maintenance activities if even one unit is found out of tolerance or causes a Misoperation.

The minimum number of units that can be tested in any given year is 5% of the population. Note that this 5% threshold sets a practical limitation on total length of time between intervals at 20 years.

If at any time the number of Countable Events equals or exceeds 4% of the last year's tested components (or the last 30 units maintained, whichever is more), then the time period between manual maintenance activities must be decreased. There is a time limit on reaching the decreased time at which the Countable Events is less than 4%; this must be attained within three years.

Performance-Based Program Evaluation Example

The 4% performance target was derived as a protection system performance target and was selected based on the drafting team's experience and studies performed by several utilities. This is not derived from the performance of discrete devices. Microprocessor relays and electromechanical relays have different performance levels. It is not appropriate to compare these performance levels to each other. The performance of the segment should be compared to the 4% performance criteria.

In consideration of the use of Performance Based Maintenance (PBM), the user should consider the effects of extended testing intervals and the established 4% failure rate. In the table shown below, the segment is 1000 units. As the testing interval (in years) increases, the number of units tested each year decreases. The number of countable events allowed is 4% of the tested units. Countable events are the failure of a Component requiring repair or replacement, any corrective actions performed during the maintenance test on the units within the testing segment (units per year), or any misoperation attributable to hardware failure or calibration failure found within the entire segment (1000 units) during the testing year.

Example: 1000 units in the segment with a testing interval of 8 years: The number of units tested each year will be 125 units. The total allowable countable events equals: 125 X .04 = 5. This number includes failure of a Component requiring repair or replacement, corrective issues found during testing, and the total number of misoperations (attributable to hardware or calibration failure within the testing year) associated with the entire segment of 1000 units.

Example: 1000 units in the segment with a testing interval of 16 years: The number of units tested each year will be 63 units. The total allowable countable events equals: 63 X .04 = 2.5.

As shown in the above examples, doubling the testing interval reduces the number of allowable events by half.

Total number of units in the segment	1000
Failure rate	4.00%

Testing Intervals (Years)	Units Per Year	Acceptable Number of Countable Events per year	Yearly Failure Rate Based on 1000 Units in Segment
1	1000.00	40.00	4.00%
2	500.00	20.00	2.00%
4	250.00	10.00	1.00%
6	166.67	6.67	0.67%
8	125.00	5.00	0.50%
10	100.00	4.00	0.40%
12	83.33	3.33	0.33%
14	71.43	2.86	0.29%
16	62.50	2.50	0.25%
18	55.56	2.22	0.22%
20	50.00	2.00	0.20%

Using the prior year's data, determine the maximum allowable maintenance interval for each Segment such that the Segment experiences Countable Events on no more than 4% of the Components within the Segment, for the greater of either the last 30 Components maintained or all Components maintained in the previous year.

Segment – Components of a consistent design standard, or a particular model or type from a single manufacturer that typically share other common elements. Consistent performance is expected across the entire population of a Segment. A Segment must contain at least sixty (60) individual Components.

Countable Event – A failure of a Component requiring repair or replacement, any condition discovered during the maintenance activities in Tables 1-1 through 1-5, Table 3, Table 4-1 through Table 4-2, and Table 5, which requires corrective action or a Protection System Misoperation attributed to hardware failure or calibration failure. Misoperations due to product design errors, software errors, relay settings different from specified settings, Protection System Component, Automatic Reclosing, or Sudden Pressure Relaying configuration or application errors are not included in Countable Events.

9.2 Frequently Asked Questions:

I'm a small entity and cannot aggregate a population of Protection System components to establish a segment required for a Performance-Based Protection System Maintenance Program. How can I utilize that opportunity?

Multiple asset owning entities may aggregate their individually owned populations of individual Protection System components to create a segment that crosses ownership boundaries. All entities participating in a joint program should have a single documented joint management

process, with consistent Protection System Maintenance Programs (practices, maintenance intervals and criteria), for which the multiple owners are individually responsible with respect to the requirements of the Standard. The requirements established for Performance-Based Maintenance must be met for the overall aggregated program on an ongoing basis.

The aggregated population should reflect all factors that affect consistent performance across the population, including any relevant environmental factors such as geography, power-plant vs. substation, and weather conditions.

Can an owner go straight to a Performance-Based Maintenance program schedule, if they have previously gathered records?

Yes. An owner can go to a Performance-Based Maintenance program immediately. The owner will need to comply with the requirements of a Performance-Based Maintenance program as listed in the Standard. Gaps in the data collected will not be allowed; therefore, if an owner finds that a gap exists such that they cannot prove that they have collected the data as required for a Performance-Based Maintenance program then they will need to wait until they can prove compliance.

When establishing a Performance-Based Maintenance program, can I use test data from the device manufacturer, or industry survey results, as results to help establish a basis for my Performance-Based intervals?

No, you must use actual in-service test data for the components in the segment.

What types of Misoperations or events are not considered Countable Events in the Performance-Based Protection System Maintenance (PBM) Program?

Countable Events are intended to address conditions that are attributed to hardware failure or calibration failure; that is, conditions that reflect deteriorating performance of the component. These conditions include any condition where the device previously worked properly, then, due to changes within the device, malfunctioned or degraded to the point that re-calibration (to within the entity's tolerance) was required.

For this purpose of tracking hardware issues, human errors resulting in Protection System Misoperations during system installation or maintenance activities are not considered Countable Events. Examples of excluded human errors include relay setting errors, design errors, wiring errors, inadvertent tripping of devices during testing or installation, and misapplication of Protection System components. Examples of misapplication of Protection System components include wrong CT or PT tap position, protective relay function misapplication, and components not specified correctly for their installation. Obviously, if one is setting up relevant data about hardware failures then human failures should be eliminated from the hardware performance analysis.

One example of human-error is not pertinent data might be in the area of testing "86" lock-out relays (LOR). "Entity A" has two types of LOR's type "X" and type "Y"; they want to move into a performance based maintenance interval. They have 1000 of each type, so the population variables are met. During electrical trip testing of all of their various schemes over the initial six-year interval they find zero type "X" failures, but human error led to tripping a BES Element 100 times; they find 100 type "Y" failures and had an additional 100 human-error caused tripping incidents. In this example the human-error caused Misoperations should not be used to judge the performance of either type of LOR. Analysis of the data might lead "Entity A" to change time intervals. Type "X" LOR can be placed into extended time interval testing because of its low failure

rate (zero failures) while Type “Y” would have to be tested more often than every 6 calendar years (100 failures divided by 1000 units exceeds the 4% tolerance level).

Certain types of Protection System component errors that cause Misoperations are not considered Countable Events. Examples of excluded component errors include device malfunctions that are correctable by firmware upgrades and design errors that do not impact protection function.

What are some examples of methods of correcting segment perfomance for Performance-Based Maintenance?

There are a number of methods that may be useful for correcting segment performance for mal-performing segments in a Performance-Based Maintenance system. Some examples are listed below.

- The maximum allowable interval, as established by the Performance-Based Maintenance system, can be decreased. This may, however, be slow to correct the performance of the segment.
- Identifiable sub-groups of components within the established segment, which have been identified to be the mal-performing portion of the segment, can be broken out as an independent segment for target action. Each resulting segment must satisfy the minimum population requirements for a Performance-Based Maintenance program in order to remain within the program.
- Targeted corrective actions can be taken to correct frequently occurring problems. An example would be replacement of capacitors within electromechanical distance relays if bad capacitors were determined to be the cause of the mal-performance.
- components within the mal-performing segment can be replaced with other components (electromechanical distance relays with microprocessor relays, for example) to remove the mal-performing segment.

If I find (and correct) a Unresolved Maintenance Issue as a result of a Misoperation investigation (Re: PRC-004), how does this affect my Performance-Based Maintenance program?

If you perform maintenance on a Protection System component for any reason (including as part of a PRC-004 required Misoperation investigation/corrective action), the actions performed can count as a maintenance activity provided the activities in the relevant Tables have been done, and, if you desire, “reset the clock” on everything you’ve done. In a Performance-Based Maintenance program, you also need to record the Unresolved Maintenance Issue as a Countable Event within the relevant component group segment and use it in the analysis to determine your correct Performance-Based Maintenance interval for that component group. Note that “resetting the clock” should not be construed as interfering with an entity’s routine testing schedule because the “clock-reset” would actually make for a decreased time interval by the time the next routine test schedule comes around.

For example a relay scheme, consisting of four relays, is tested on 1-1-11 and the PSMP has a time interval of 3 calendar years with an allowable extension of 1 calendar year. The relay would be due again for routine testing before the end of the year 2015. This mythical relay scheme has a Misoperation on 6-1-12 that points to one of the four relays as bad. Investigation proves a bad

relay and a new one is tested and installed in place of the original. This replacement relay actually could be retested before the end of the year 2016 (clock-reset) and not be out of compliance. This requires tracking maintenance by individual relays and is allowed. However, many companies schedule maintenance in other ways like by substation or by circuit breaker or by relay scheme. By these methods of tracking maintenance that “replaced relay” will be retested before the end of the year 2015. This is also acceptable. In no case was a particular relay tested beyond the PSMP of four years max, nor was the 6 year max of the Standard exceeded. The entity can reset the clock if they desire or the entity can continue with original schedules and, in effect, test even more frequently.

Why are batteries excluded from PBM? What about exclusion of batteries from condition based maintenance?

Batteries are the only element of a Protection System that is a perishable item with a shelf life. As a perishable item batteries require not only a constant float charge to maintain their freshness (charge), but periodic inspection to determine if there are problems associated with their aging process and testing to see if they are maintaining a charge or can still deliver their rated output as required.

Besides being perishable, a second unique feature of a battery that is unlike any other Protection System element is that a battery uses chemicals, metal alloys, plastics, welds, and bonds that must interact with each other to produce the constant dc source required for Protection Systems, undisturbed by ac system Disturbances.

No type of battery manufactured today for Protection System application is free from problems that can only be detected over time by inspection and test. These problems can arise from variances in the manufacturing process, chemicals and alloys used in the construction of the individual cells, quality of welds and bonds to connect the components, the plastics used to make batteries and the cell forming process for the individual battery cells.

Other problems that require periodic inspection and testing can result from transportation from the factory to the job site, length of time before a charge is put on the battery, the method of installation, the voltage level and duration of equalize charges, the float voltage level used, and the environment that the battery is installed in.

All of the above mentioned factors and several more not discussed here are beyond the control of the Functional Entities that want to use a Performance-Based Protection System Maintenance (PBM) program. These inherent variances in the aging process of a battery cell make establishment of a designated segment based on manufacturer and type of battery impossible.

The whole point of PBM is that if all variables are isolated then common aging and performance criteria would be the same. However, there are too many variables in the electrochemical process to completely isolate all of the performance-changing criteria.

Similarly, Functional Entities that want to establish a condition-based maintenance program using the highest levels of monitoring, resulting in the least amount of hands-on maintenance activity, cannot completely eliminate some periodic maintenance of the battery used in a station dc supply. Inspection of the battery is required on a Maximum Maintenance Interval listed in the tables due to the aging processes of station batteries. However, higher degrees of

monitoring of a battery can eliminate the requirement for some periodic testing and some inspections (see Table 1-4).

Please provide an example of the calculations involved in extending maintenance time intervals using PBM.

Entity has 1000 GE-HEA lock-out relays; this is greater than the minimum sample requirement of 60. They start out testing all of the relays within the prescribed Table requirements (6 year max) by testing the relays every 5 years. The entity's plan is to test 200 units per year; this is greater than the minimum sample size requirement of 30. For the sake of example only the following will show 6 failures per year, reality may well have different numbers of failures every year. PBM requires annual assessment of failures found per units tested. After the first year of tests the entity finds 6 failures in the 200 units tested. 6/200= 3% failure rate. This entity is now allowed to extend the maintenance interval if they choose. The entity chooses to extend the maintenance interval of this population segment out to 10 years. This represents a rate of 100 units tested per year; entity selects 100 units to be tested in the following year. After that year of testing these 100 units the entity again finds 6 failed units. 6/100= 6% failures. This entity has now exceeded the acceptable failure rate for these devices and must accelerate testing of all of the units at a higher rate such that the failure rate is found to be less than 4% per year; the entity has three years to get this failure rate down to 4% or less (per year). In response to the 6% failure rate, the entity decreases the testing interval to 8 years. This means that they will now test 125 units per year (1000/8). The entity has just two years left to get the test rate corrected.

After a year, they again find six failures out of the 125 units tested. 6/125= 5% failures. In response to the 5% failure rate, the entity decreases the testing interval to seven years. This means that they will now test 143 units per year (1000/7). The entity has just one year left to get the test rate corrected. After a year, they again find six failures out of the 143 units tested. 6/143= 4.2% failures.

(Note that the entity has tried five years and they were under the 4% limit and they tried seven years and they were over the 4% limit. They must be back at 4% failures or less in the next year so they might simply elect to go back to five years.)

Instead, in response to the 5% failure rate, the entity decreases the testing interval to six years. This means that they will now test 167 units per year (1000/6). After a year, they again find six failures out of the 167 units tested. 6/167= 3.6% failures. Entity found that they could maintain the failure rate at no more than 4% failures by maintaining the testing interval at six years or less. Entity chose six-year interval and effectively extended their TBM (five years) program by 20%.

A note of practicality is that an entity will probably be in better shape to lengthen the intervals between tests if the failure rate is less than 2%. But the requirements allow for annual adjustments, if the entity desires. As a matter of maintenance management, an ever-changing test rate (units tested/year) may be un-workable.

Note that the "5% of components" requirement effectively sets a practical limit of 20 year maximum PBM interval. Also of note is the "3 years" requirement; an entity might arbitrarily extend time intervals from six years to 20 years. In the event that an entity finds a failure rate greater than 4%, then the test rate must be accelerated such that within three years the failure rate must be brought back down to 4% or less.

Here is a table that demonstrates the values discussed:

Year #	Total Population (P)	Test Interval (I)	Units to be Tested (U= P/I)	# of Failures Found (F)	Failure Rate (=F/U)	Decision to Change Interval Yes or No	Interval Chosen
1	1000	5 yrs	200	6	3%	Yes	10 yrs
2	1000	10 yrs	100	6	6%	Yes	8 yrs
3	1000	8 yrs	125	6	5%	Yes	7 yrs
4	1000	7 yrs	143	6	4.2%	Yes	6 yrs
5	1000	6 yrs	167	6	3.6%	No	6 yrs

Please provide an example of the calculations involved in extending maintenance time intervals using PBM for control circuitry.

Note that the following example captures "Control Circuitry" as all of the trip paths associated with a particular trip coil of a circuit breaker. An entity is not restricted to this method of counting control circuits. Perhaps another method an entity would prefer would be to simply track every individual (parallel) trip path. Or perhaps another method would be to track all of the trip outputs from a specific (set) of relays protecting a specific element.

The designation of what constitutes a control circuit component is very dependent upon how an entity performs and tracks the testing of the control circuitry. Some entities test their control circuits on a breaker basis whereas others test their circuitry on a local zone of protection basis. Thus, entities are allowed the latitude to designate their own definitions of control circuit components. Another example of where the entity has some discretion on determining what constitutes a single component is the voltage and current sensing devices, where the entity may choose either to designate a full three-phase set of such devices or a single device as a single component.

And in Attachment A (PBM) the definition of Segment:

Segment –*Components of a consistent design standard, or a particular model or type from a single manufacturer that typically share other common elements. Consistent performance is expected across the entire population of a segment. A segment must contain at least sixty (60) individual components.*

Example:

Entity has 1,000 circuit breakers, all of which have two trip coils, for a total of 2,000 trip coils; if all circuitry was designed and built with a consistent (internal entity) standard, then this is greater than the minimum sample requirement of 60.

For the sake of further example, the following facts are given:

Half of all relay panels (500) were built 40 years ago by an outside contractor, consisted of asbestos wrapped 600V-insulation panel wiring, and the cables exiting the control house are THHN pulled in conduit direct to exactly half of all of the various circuit breakers. All of the relay panels and cable pulls were built with consistent standards and consistent performance standard expectations within the segment (which is greater than 60). Each relay panel has redundant microprocessor (MPC) relays (retrofitted); each MPC relay supplies an individual trip output to each of the two trip coils of the assigned circuit breaker.

Approximately 35 years ago, the entity developed their own internal construction crew and now builds all of their own relay panels from parts supplied from vendors that meet the entity's specifications, including SIS 600V insulation wiring and copper-sheathed cabling within the direct conduits to circuit breakers. The construction crew uses consistent standards in the construction. This newer segment of their control circuitry population is different than the original segment, consistent (standards, construction and performance expectations) within the new segment and constitutes the remainder of the entity's population (another 500 panels and the cabling to the remaining 500 circuit breakers). Each relay panel has redundant microprocessor (MPC) relays; each MPC relay supplies an individual trip output to each of the two trip coils of the assigned circuit breaker. Every trip path in this newer segment has a device that monitors the voltage

directly across the trip contacts of the MPC relays and alarms via RTU and SCADA to the operations control room. This monitoring device, when not in alarm, demonstrates continuity all the way through the trip coil, cabling and wiring back to the trip contacts of the MPC relay.

The entity is tracking 2,000 trip coils (each consisting of multiple trip paths) in each of these two segments. But half of all of the trip paths are monitored; therefore, the trip paths are continuously tested and the circuit will alarm when there is a failure. These alarms have to be verified every 12 years for correct operation.

The entity now has 1,000 trip coils (and associated trip paths) remaining that they have elected to count as control circuits. The entity has instituted a process that requires the verification of every trip path to each trip coil (one unit), including the electrical activation of the trip coil. (The entity notes that the trip coils will have to be tripped electrically more often than the trip path verification, and is taking care of this activity through other documentation of Real-time Fault operations.)

They start out testing all of the trip coil circuits within the prescribed Table requirements (12-year max) by testing the trip circuits every 10 years. The entity's plan is to test 100 units per year; this is greater than the minimum sample size requirement of 30. For the sake of example only, the following will show three failures per year; reality may well have different numbers of failures every year. PBM requires annual assessment of failures found per units tested. After the first year of tests, the entity finds three failures in the 100 units tested. 3/100= 3% failure rate.

This entity is now allowed to extend the maintenance interval, if they choose. The entity chooses to extend the maintenance interval of this population segment out to 20 years. This represents a rate of 50 units tested per year; entity selects 50 units to be tested in the following year. After that year of testing these 50 units, the entity again finds three failed units. 3/50= 6% failures.

This entity has now exceeded the acceptable failure rate for these devices and must accelerate testing of all of the units at a higher rate, such that the failure rate is found to be less than 4% per year; the entity has three years to get this failure rate down to 4% or less (per year).

In response to the 6% failure rate, the entity decreases the testing interval to 16 years. This means that they will now test 63 units per year (1000/16). The entity has just two years left to get the test rate corrected. After a year, they again find three failures out of the 63 units tested. 3/63= 4.76% failures.

In response to the >4% failure rate, the entity decreases the testing interval to 14 years. This means that they will now test 72 units per year (1000/14). The entity has just one year left to get the test rate corrected. After a year, they again find three failures out of the 72 units tested. 3/72= 4.2% failures.

(Note that the entity has tried 10 years, and they were under the 4% limit; and they tried 14 years, and they were over the 4% limit. They must be back at 4% failures or less in the next year, so they might simply elect to go back to 10 years.)

Instead, in response to the 4.2% failure rate, the entity decreases the testing interval to 12 years. This means that they will now test 84 units per year (1000/12). After a year, they again find three failures out of the 84 units tested. 3/84= 3.6% failures.

Entity found that they could maintain the failure rate at no more than 4% failures by maintaining the testing interval at 12 years or less. Entity chose 12-year interval, and effectively extended their TBM (10 years) program by 20%.

A note of practicality is that an entity will probably be in better shape to lengthen the intervals between tests if the failure rate is less than 2%. But the requirements allow for annual adjustments if the entity desires. As a matter of maintenance management, an ever-changing test rate (units tested / year) may be un-workable.

Note that the "5% of components" requirement effectively sets a practical limit of 20-year maximum PBM interval. Also of note is the "3 years" requirement; an entity might arbitrarily extend time intervals from six years to 20 years. In the event that an entity finds a failure rate greater than 4%, then the test rate must be accelerated such that within three years the failure rate must be brought back down to 4% or less.

Here is a table that demonstrates the values discussed:

Year #	Total Population (P)	Test Interval (I)	Units to be Tested (U= P/I)	# of Failures Found (F)	Failure Rate (=F/U)	Decision to Change Interval Yes or No	Interval Chosen
1	1000	10 yrs	100	3	3%	Yes	20 yrs
2	1000	20 yrs	50	3	6%	Yes	16yrs
3	1000	16 yrs	63	3	4.8%	Yes	14 yrs
4	1000	14 yrs	72	3	4.2%	Yes	12 yrs
5	1000	12 yrs	84	3	3.6%	No	12 yrs

Please provide an example of the calculations involved in extending maintenance time intervals using PBM for voltage and current sensing devices.

Note that the following example captures "voltage and current inputs to the protective relays" as all of the various current transformer and potential transformer signals associated with a particular set of relays used for protection of a specific Element. This entity calls this set of protective relays a "Relay Scheme." Thus, this entity chooses to count PT and CT signals as a group instead of individually tracking maintenance activities to specific bushing CT's or specific PT's. An entity is not restricted to this method of counting voltage and current devices, signals and paths. Perhaps another method an entity would prefer would be to simply track every individual PT and CT. Note that a generation maintenance group may well select the latter because they may elect to perform routine off-line tests during generator outages, whereas a transmission maintenance group might create a process that utilizes Real-time system values measured at the relays.

The designation of what constitutes a control circuit component is very dependent upon how an entity performs and tracks the testing of the control circuitry. Some entities test their control circuits on a breaker basis whereas others test their circuitry on a local zone of protection basis. Thus, entities are allowed the latitude to designate their own definitions of control circuit components. Another example of where the entity has some discretion on determining what constitutes a single component is the voltage and current sensing devices, where the entity may choose either to designate a full three-phase set of such devices or a single device as a single component.

And in Attachment A (PBM) the definition of Segment:

Segment –*Components of a consistent design standard, or a particular model or type from a single manufacturer that typically share other common elements. Consistent performance is expected across the entire population of a segment. A segment must contain at least sixty (60) individual components.*

Example:

Entity has 2000 "Relay Schemes," all of which have three current signals supplied from bushing CTs, and three voltage signals supplied from substation bus PT's. All cabling and circuitry was designed and built with a consistent (internal entity) standard, and this population is greater than the minimum sample requirement of 60.

For the sake of further example the following facts are given:

Half of all relay schemes (1,000) are supplied with current signals from ANSI STD C800 bushing CTs and voltage signals from PTs built by ACME Electric MFR CO. All of the relay panels and cable pulls were built with consistent standards, and consistent performance standard expectations exist for the consistent wiring, cabling and instrument transformers within the segment (which is greater than 60).

The other half of the entity's relay schemes have MPC relays with additional monitoring built-in that compare DNP values of voltages and currents (or Watts and VARs), as interpreted by the MPC relays and alarm for an entity-accepted tolerance level of accuracy. This newer segment of their "Voltage and Current Sensing" population is different than the original segment, consistent (standards, construction and performance expectations) within the new segment and constitutes the remainder of the entity's population.

The entity is tracking many thousands of voltage and current signals within 2,000 relay schemes (each consisting of multiple voltage and current signals) in each of these two segments. But half of all of the relay schemes voltage and current signals are monitored; therefore, the voltage and current signals are continuously tested and the circuit will alarm when there is a failure; these alarms have to be verified every 12 years for correct operation.

The entity now has 1,000 relay schemes worth of voltage and current signals remaining that they have elected to count within their relay schemes designation. The entity has instituted a process that requires the verification of these voltage and current signals within each relay scheme (one unit).

(Please note - a problem discovered with a current or voltage signal found at the relay could be caused by anything from the relay, all the way to the signal source itself. Having many sources of problems can easily increase failure rates beyond the rate of failures of just one item (for example just PTs). It is the intent of the SDT to minimize failure rates of all of the equipment to an acceptable level; thus, any failure of any item that gets the signal from source to relay is counted. It is for this reason that the SDT chose to set the boundary at the ability of the signal to be delivered all the way to the relay.

The entity will start out measuring all of the relay scheme voltage and currents at the individual relays within the prescribed Table requirements (12 year max) by measuring the voltage and current values every 10 years. The entity's plan is to test 100 units per year; this is greater than the minimum sample size requirement of 30. For the sake of example only, the following will show three failures per year; reality may well have different numbers of failures every year. PBM requires annual assessment of failures found per units tested. After the first year of tests, the entity finds three failures in the 100 units tested. 3/100= 3% failure rate.

This entity is now allowed to extend the maintenance interval, if they choose. The entity chooses to extend the maintenance interval of this population segment out to 20 years. This represents a rate of 50 units tested per year; entity selects 50 units to be tested in the following year. After that year of testing these 50 units, the entity again finds three failed units. 3/50= 6% failures.

This entity has now exceeded the acceptable failure rate for these devices and must accelerate testing of all of the units at a higher rate, such that the failure rate is found to be less than 4% per year; the entity has three years to get this failure rate down to 4% or less (per year).

In response to the 6% failure rate, the entity decreases the testing interval to 16 years. This means that they will now test 63 units per year (1000/16). The entity has just two years left to get the test rate corrected. After a year, they again find three failures out of the 63 units tested. 3/63= 4.76% failures.

In response to the >4%failure rate, the entity decreases the testing interval to 14 years. This means that they will now test 72 units per year (1000/14). The entity has just one year left to get the test rate corrected. After a year, they again find three failures out of the 72 units tested. 3/72= 4.2% failures.

(Note that the entity has tried 10 years, and they were under the 4% limit; and they tried 14 years, and they were over the 4% limit. They must be back at 4% failures or less in the next year, so they might simply elect to go back to 10 years.)

Instead, in response to the 4.2% failure rate, the entity decreases the testing interval to 12 years. This means that they will now test 84 units per year (1,000/12). After a year, they again find three failures out of the 84 units tested. 3/84= 3.6% failures.

Entity found that they could maintain the failure rate at no more than 4% failures by maintaining the testing interval at 12 years or less. Entity chose 12-year interval and effectively extended their TBM (10 years) program by 20%.

A note of practicality is that an entity will probably be in better shape to lengthen the intervals between tests if the failure rate is less than 2%. But the requirements allow for annual adjustments, if the entity desires. As a matter of maintenance management, an ever-changing test rate (units tested/year) may be un-workable.

Note that the “5% of components” requirement effectively sets a practical limit of 20-year maximum PBM interval. Also of note is the “3 years” requirement; an entity might arbitrarily extend time intervals from six years to 20 years. In the event that an entity finds a failure rate greater than 4%, then the test rate must be accelerated such that within three years the failure rate must be brought back down to 4% or less.

Here is a table that demonstrates the values discussed:

Year #	Total Population (P)	Test Interval (I)	Units to be Tested (U= P/I)	# of Failures Found (F)	Failure Rate (=F/U)	Decision to Change Interval Yes or No	Interval Chose
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3	1000	16 yrs	63	3	4.8%	Yes	14 yrs
4	1000	14 yrs	72	3	4.2%	Yes	12 yrs
5	1000	12 yrs	84	3	3.6%	No	12 yrs

10. Overlapping the Verification of Sections of the Protection System

Tables 1-1 through 1-5 require that every Protection System component be periodically verified. One approach, but not the only method, is to test the entire protection scheme as a unit, from the secondary windings of voltage and current sources to breaker tripping. For practical ongoing verification, sections of the Protection System may be tested or monitored individually. The boundaries of the verified sections must overlap to ensure that there are no gaps in the verification. See Appendix A of this Supplementary Reference for additional discussion on this topic.

All of the methodologies expressed within this report may be combined by an entity, as appropriate, to establish and operate a maintenance program. For example, a Protection System may be divided into multiple overlapping sections with a different maintenance methodology for each section:

- Time-based maintenance with appropriate maximum verification intervals for categories of equipment, as given in the Tables 1-1 through 1-5;
- Monitoring as described in Tables 1-1 through 1-5;
- A Performance-Based Maintenance program as described in Section 9 above, or Attachment A of the standard;
- Opportunistic verification using analysis of Fault records, as described in Section 11

10.1 Frequently Asked Questions:

My system has alarms that are gathered once daily through an auto-polling system; this is not really a conventional SCADA system but does it meet the Table 1 requirements for inclusion as a monitored system?

Yes, provided the auto-polling that gathers the alarms reports those alarms to a location where the action can be initiated to correct the Unresolved Maintenance Issue. This location does not have to be the location of the engineer or the technician that will eventually repair the problem, but rather a location where the action can be initiated.

11. Monitoring by Analysis of Fault Records

Many users of microprocessor relays retrieve Fault event records and oscillographic records by data communications after a Fault. They analyze the data closely if there has been an apparent Misoperation, as NERC standards require. Some advanced users have commissioned automatic Fault record processing systems that gather and archive the data. They search for evidence of component failures or setting problems hidden behind an operation whose overall outcome seems to be correct. The relay data may be augmented with independently captured Digital Fault Recorder (DFR) data retrieved for the same event.

Fault data analysis comprises a legitimate CBM program that is capable of reducing the need for a manual time-interval based check on Protection Systems whose operations are analyzed. Even electromechanical Protection Systems instrumented with DFR channels may achieve some CBM benefit. The completeness of the verification then depends on the number and variety of Faults in the vicinity of the relay that produce relay response records and the specific data captured.

A typical Fault record will verify particular parts of certain Protection Systems in the vicinity of the Fault. For a given Protection System installation, it may or may not be possible to gather within a reasonable amount of time an ensemble of internal and external Fault records that completely verify the Protection System.

For example, Fault records may verify that the particular relays that tripped are able to trip via the control circuit path that was specifically used to clear that Fault. A relay or DFR record may indicate correct operation of the protection communications channel. Furthermore, other nearby Protection Systems may verify that they restrain from tripping for a Fault just outside their respective zones of protection. The ensemble of internal Fault and nearby external Fault event data can verify major portions of the Protection System, and reset the time clock for the Table 1 testing intervals for the verified components only.

What can be shown from the records of one operation is very specific and limited. In a panel with multiple relays, only the specific relay(s) whose operation can be observed without ambiguity should be used. Be careful about using Fault response data to verify that settings or calibration are correct. Unless records have been captured for multiple Faults close to either side of a setting boundary, setting or calibration could still be incorrect.

PMU data, much like DME data, can be utilized to prove various components of the Protection System. Obviously, care must be taken to attribute proof only to the parts of a Protection System that can actually be proven using the PMU or DME data.

If Fault record data is used to show that portions or all of a Protection System have been verified to meet Table 1 requirements, the owner must retain the Fault records used, and the maintenance-related conclusions drawn from this data and used to defer Table 1 tests, for at least the retention time interval given in Section 8.2.

11.1 Frequently Asked Questions:

I use my protective relays for Fault and Disturbance recording, collecting oscillographic records and event records via communications for Fault analysis to meet NERC and DME requirements. What are the maintenance requirements for the relays?

For relays used only as Disturbance Monitoring Equipment, NERC Standard PRC-018-1 R3 & R6 states the maintenance requirements and is being addressed by a standards activity that is revising PRC-002-1 and PRC-018-1. For protective relays “that are designed to provide protection for the BES,” this standard applies, even if they also perform DME functions.

12. Importance of Relay Settings in Maintenance Programs

In manual testing programs, many utilities depend on pickup value or zone boundary tests to show that the relays have correct settings and calibration. Microprocessor relays, by contrast, provide the means for continuously monitoring measurement accuracy. Furthermore, the relay digitizes inputs from one set of signals to perform all measurement functions in a single self-monitoring microprocessor system. These relays do not require testing or calibration of each setting.

However, incorrect settings may be a bigger risk with microprocessor relays than with older relays. Some microprocessor relays have hundreds or thousands of settings, many of which are critical to Protection System performance.

Monitoring does not check measuring element settings. Analysis of Fault records may or may not reveal setting problems. To minimize risk of setting errors after commissioning, the user should enforce strict settings data base management, with reconfirmation (manual or automatic) that the installed settings are correct whenever maintenance activity might have changed them; for background and guidance, see [5] in References.

Table 1 requires that settings must be verified to be as specified. The reason for this requirement is simple: With legacy relays (non-microprocessor protective relays), it is necessary to know the value of the intended setting in order to test, adjust and calibrate the relay. Proving that the relay works per specified setting was the de facto procedure. However, with the advanced microprocessor relays, it is possible to change relay settings for the purpose of verifying specific functions and then neglect to return the settings to the specified values. While there is no specific requirement to maintain a settings management process, there remains a need to verify that the settings left in the relay are the intended, specified settings. This need may manifest itself after any of the following:

- One or more settings are changed for any reason.
- A relay fails and is repaired or replaced with another unit.
- A relay is upgraded with a new firmware version.

12.1 Frequently Asked Questions:

How do I approach testing when I have to upgrade firmware of a microprocessor relay?

The entity should ensure that the relay continues to function properly after implementation of firmware changes. Some entities may have a R&D department that might routinely run acceptance tests on devices with firmware upgrades before allowing the upgrade to be installed. Other entities may rely upon the vigorous testing of the firmware OEM. An entity has the latitude to install devices and/or programming that they believe will perform to their satisfaction. If an entity should choose to perform the maintenance activities specified in the Tables following a firmware upgrade, then they may, if they choose, reset the time clock on that set of maintenance activities so that they would not have to repeat the maintenance on its regularly scheduled cycle.

(However, for simplicity in maintenance schedules, some entities may choose to not reset this time clock; it is merely a suggested option.)

If I upgrade my old relays, then do I have to maintain my previous equipment maintenance documentation?

If an equipment item is repaired or replaced, then the entity can restart the maintenance-activity-time-interval-clock, if desired; however, the replacement of equipment does not remove any documentation requirements. The requirements in the standard are intended to ensure that an entity has a maintenance plan, and that the entity adheres to minimum activities and maximum time intervals. The documentation requirements are intended to help an entity demonstrate compliance. For example, saving the dates and records of the last two maintenance activities is intended to demonstrate compliance with the interval. Therefore, if you upgrade or replace equipment, then you still must maintain the documentation for the previous equipment, thus demonstrating compliance with the time interval requirement prior to the replacement action.

We have a number of installations where we have changed our Protection System components. Some of the changes were upgrades, but others were simply system rating changes that merely required taking relays "out-of-service". What are our responsibilities when it comes to "out-of-service" devices?

Assuming that your system up-rates, upgrades and overall changes meet any and all other requirements and standards, then the requirements of PRC-005-4 are simple – if the Protection System component performs a Protection System function, then it must be maintained. If the component no longer performs Protection System functions, then it does not require maintenance activities under the Tables of PRC-005-4. While many entities might physically remove a component that is no longer needed, there is no requirement in PRC-005-4 to remove such component(s). Obviously, prudence would dictate that an "out-of-service" device is truly made inactive. There are no record requirements listed in PRC-005-4 for Protection System components not used.

While performing relay testing of a protective device on our Bulk Electric System, it was discovered that the protective device being tested was either broken or out of calibration. Does this satisfy the relay testing requirement, even though the protective device tested bad, and may be unable to be placed back into service?

Yes, PRC-005-4 requires entities to perform relay testing on protective devices on a given maintenance cycle interval. By performing this testing, the entity has satisfied PRC-005-4 requirement, although the protective device may be unable to be returned to service under normal calibration adjustments. R5 states:

"R5. Each Transmission Owner, Generator Owner, and Distribution Provider shall demonstrate efforts to correct any identified Unresolved Maintenance Issues."

Also, when a failure occurs in a Protection System, power system security may be comprised, and notification of the failure must be conducted in accordance with relevant NERC standards.

If I show the protective device out of service while it is being repaired, then can I add it back as a new protective device when it returns? If not, my relay testing history would show that I was out of compliance for the last maintenance cycle.

The maintenance and testing requirements (R5) state "…shall demonstrate efforts to correct any identified Unresolved Maintenance Issues..." The type of corrective activity is not stated; however, it could include repairs or replacements.

Your documentation requirements will increase, of course, to demonstrate that your device tested bad and had corrective actions initiated. Your regional entity might ask about the status of your corrective actions.

13. Self-Monitoring Capabilities and Limitations

Microprocessor relay proponents have cited the self-monitoring capabilities of these products for nearly 20 years. Theoretically, any element that is monitored does not need a periodic manual test. A problem today is that the community of manufacturers and users has not created clear documentation of exactly what is and is not monitored. Some unmonitored but critical elements are buried in installed systems that are described as self-monitoring.

To utilize the extended time intervals allowed by monitoring, the user must document that the monitoring attributes of the device match the minimum requirements listed in the Table 1.

Until users are able to document how all parts of a system which are required for the protective functions are monitored or verified (with help from manufacturers), they must continue with the unmonitored intervals established in Table 1 and Table 3.

Going forward, manufacturers and users can develop mappings of the monitoring within relays, and monitoring coverage by the relay of user circuits connected to the relay terminals.

To enable the use of the most extensive monitoring (and never again have a hands-on maintenance requirement), the manufacturers of the microprocessor-based self-monitoring components in the Protection System should publish for the user a document or map that shows:

- How all internal elements of the product are monitored for any failure that could impact Protection System performance.
- Which connected circuits are monitored by checks implemented within the product; how to connect and set the product to assure monitoring of these connected circuits; and what circuits or potential problems are not monitored.

This manufacturer's information can be used by the registered entity to document compliance of the monitoring attributes requirements by:

- Presenting or referencing the product manufacturer's documents.
- Explaining in a system design document the mapping of how every component and circuit that is critical to protection is monitored by the microprocessor product(s) or by other design features.
- Extending the monitoring to include the alarm transmission Facilities through which failures are reported within a given time frame to allocate where action can be taken to initiate resolution of the alarm attributed to an Unresolved Maintenance Issue, so that failures of monitoring or alarming systems also lead to alarms and action.
- Documenting the plans for verification of any unmonitored components according to the requirements of Table 1 and Table 3.

13.1 Frequently Asked Questions:

I can't figure out how to demonstrate compliance with the requirements for the highest level of monitoring of Protection Systems. Why does this Maintenance Standard describe a maintenance program approach I cannot achieve?

Demonstrating compliance with the requirements for the highest level of monitoring any particular component of Protection Systems is likely to be very involved, and may include detailed manufacturer documentation of complete internal monitoring within a device, comprehensive design drawing reviews, and other detailed documentation. This standard does not presume to specify what documentation must be developed; only that it must be documented.

There may actually be some equipment available that is capable of meeting these highest levels of monitoring criteria, in which case it may be maintained according to the highest level of monitoring shown on the Tables. However, even if there is no equipment available today that can meet this level of monitoring, the standard establishes the necessary requirements for when such equipment becomes available.

By creating a roadmap for development, this provision makes the standard technology-neutral. The Standard Drafting Team wants to avoid the need to revise the standard in a few years to accommodate technology advances that may be coming to the industry.

14. Notification of Protection System or Automatic Reclosing Failures

When a failure occurs in a Protection System or Automatic Reclosing, power system security may be compromised, and notification of the failure must be conducted in accordance with relevant NERC standard(s). Knowledge of the failure may impact the system operator's decisions on acceptable Loading conditions.

This formal reporting of the failure and repair status to the system operator by the Protection System or Automatic Reclosing owner also encourages the system owner to execute repairs as rapidly as possible. In some cases, a microprocessor relay or carrier set can be replaced in hours; wiring termination failures may be repaired in a similar time frame. On the other hand, a component in an electromechanical or early-generation electronic relay may be difficult to find and may hold up repair for weeks. In some situations, the owner may have to resort to a temporary protection panel, or complete panel replacement.

15. Maintenance Activities

Some specific maintenance activities are a requirement to ensure reliability. An example would be that a BES entity could be prudent in its protective relay maintenance, but if its battery maintenance program is lacking, then reliability could still suffer. The NERC glossary outlines a Protection System as containing specific components. PRC-005-4 requires specific maintenance activities be accomplished within a specific time interval. As noted previously, higher technology equipment can contain integral monitoring capability that actually performs maintenance verification activities routinely and often; therefore, *manual intervention* to perform certain activities on these type components may not be needed.

15.1 Protective Relays (Table 1-1)

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 Element of the BES. Devices that sense thermal, vibration, seismic, gas, or any other non-electrical inputs are excluded.

Non-microprocessor based equipment is treated differently than microprocessor-based equipment in the following ways; the relays should meet the asset owners' tolerances:

- Non-microprocessor devices must be tested with voltage and/or current applied to the device.
- Microprocessor devices may be tested through the integral testing of the device.
  - There is no specific protective relay commissioning test or relay routine test mandated.
  - There is no specific documentation mandated.

15.1.1 Frequently Asked Questions:

What calibration tolerance should be applied on electromechanical relays?

Each entity establishes their own acceptable tolerances when applying protective relaying on their system. For some Protection System components, adjustment is required to bring measurement accuracy within the parameters established by the asset owner based on the specific application of the component. A calibration failure is the result if testing finds the specified parameters to be out of tolerance.

15.2 Voltage & Current Sensing Devices (Table 1-3)

These are the current and voltage sensing devices, usually known as instrument transformers. There is presently a technology available (fiber-optic Hall-effect) that does not utilize conventional transformer technology; these devices and other technologies that produce quantities that represent the primary values of voltage and current are considered to be a type of voltage and current sensing devices included in this standard.

The intent of the maintenance activity is to verify the input to the protective relay from the device that produces the current or voltage signal sample.

There is no specific test mandated for these components. The important thing about these signals is to know that the expected output from these components actually reaches the protective relay. Therefore, the proof of the proper operation of these components also demonstrates the integrity of the wiring (or other medium used to convey the signal) from the current and voltage sensing device, all the way to the protective relay. The following observations apply:

- There is no specific ratio test, routine test or commissioning test mandated.
- There is no specific documentation mandated.
- It is required that the signal be present at the relay.
- This expectation can be arrived at from any of a number of means; including, but not limited to, the following: By calculation, by comparison to other circuits, by commissioning tests, by thorough inspection, or by any means needed to verify the circuit meets the asset owner's Protection System maintenance program.
- An example of testing might be a saturation test of a CT with the test values applied at the relay panel; this, therefore, tests the CT, as well as the wiring from the relay all the back to the CT.
- Another possible test is to measure the signal from the voltage and/or current sensing devices, during Load conditions, at the input to the relay.
- Another example of testing the various voltage and/or current sensing devices is to query the microprocessor relay for the Real-time Loading; this can then be compared to other devices to verify the quantities applied to this relay. Since the input devices have supplied the proper values to the protective relay, then the verification activity has been satisfied. Thus, event reports (and oscillographs) can be used to verify that the voltage and current sensing devices are performing satisfactorily.
- Still another method is to measure total watts and VArs around the entire bus; this should add up to zero watts and zero VArs, thus proving the voltage and/or current sensing devices system throughout the bus.
- Another method for proving the voltage and/or current-sensing devices is to complete commissioning tests on all of the transformers, cabling, fuses and wiring.
- Any other method that verifies the input to the protective relay from the device that produces the current or voltage signal sample.

15.2.1 Frequently Asked Questions:

What is meant by "…verify the current and voltage circuit inputs from the voltage and current sensing devices to the protective relays …" Do we need to perform ratio, polarity and saturation tests every few years?

No. You must verify that the protective relay is receiving the expected values from the voltage and current-sensing devices (typically voltage and current transformers). This can be as difficult as is proposed by the question (with additional testing on the cabling and substation wiring to ensure that the values arrive at the relays); or simplicity can be achieved by other verification methods. While some examples follow, these are not intended to represent an all-inclusive list; technology advances and ingenuity should not be excluded from making comparisons and verifications:

- Compare the secondary values, at the relay, to a metering circuit, fed by different current transformers, monitoring the same line as the questioned relay circuit.
- Compare the individual phase secondary values at the relay panel (with additional testing on the panel wiring to ensure that the values arrive at those relays) with the other phases, and verify that residual currents are within expected bounds.
- Observe all three phase currents and the residual current at the relay panel with an oscilloscope, observing comparable magnitudes and proper phase relationship, with additional testing on the panel wiring to ensure that the values arrive at the relays.
- Compare the values, as determined by the questioned relay (such as, but not limited to, a query to the microprocessor relay) to another protective relay monitoring the same line, with currents supplied by different CTs.
- Compare the secondary values, at the relay with values measured by test instruments (such as, but not limited to multi-meters, voltmeter, clamp-on ammeters, etc.) and verified by calculations and known ratios to be the values expected. For example, a single PT on a 100KV bus will have a specific secondary value that, when multiplied by the PT ratio, arrives at the expected bus value of 100KV.
- Query SCADA for the power flows at the far end of the line protected by the questioned relay, compare those SCADA values to the values as determined by the questioned relay.
- Totalize the Watts and VARs on the bus and compare the totals to the values as seen by the questioned relay.

The point of the verification procedure is to ensure that all of the individual components are functioning properly; and that an ongoing proactive procedure is in place to re-check the various components of the protective relay measuring Systems.

Is wiring insulation or hi-pot testing required by this Maintenance Standard?

No, wiring insulation and equipment hi-pot testing are not specifically required by the Maintenance Standard. However, if the method of verifying CT and PT inputs to the relay involves some other method than actual observation of current and voltage transformer secondary inputs to the relay, it might be necessary to perform some sort of cable integrity test to verify that the instrument transformer secondary signals are actually making it to the relay and not being shunted off to ground. For instance, you could use CT excitation tests and PT turns ratio tests

and compare to baseline values to verify that the instrument transformer outputs are acceptable. However, to conclude that these acceptable transformer instrument output signals are actually making it to the relay inputs, it also would be necessary to verify the insulation of the wiring between the instrument transformer and the relay.

My plant generator and transformer relays are electromechanical and do not have metering functions, as do microprocessor- based relays. In order for me to compare the instrument transformer inputs to these relays to the secondary values of other metered instrument transformers monitoring the same primary voltage and current signals, it would be necessary to temporarily connect test equipment, like voltmeters and clamp on ammeters, to measure the input signals to the relays. This practice seems very risky, and a plant trip could result if the technician were to make an error while measuring these current and voltage signals. How can I avoid this risk? Also, what if no other instrument transformers are available which monitor the same primary voltage or current signal?

Comparing the input signals to the relays to the outputs of other independent instrument transformers monitoring the same primary current or voltage is just one method of verifying the instrument transformer inputs to the relays, but is not required by the standard. Plants can choose how to best manage their risk. If online testing is deemed too risky, offline tests, such as, but not limited to, CT excitation test and PT turns ratio tests can be compared to baseline data and be used in conjunction with CT and PT secondary wiring insulation verification tests to adequately “verify the current and voltage circuit inputs from the voltage and current sensing devices to the protective relays …” while eliminating the risk of tripping an in service generator or transformer. Similarly, this same offline test methodology can be used to verify the relay input voltage and current signals to relays when there are no other instrument transformers monitoring available for purposes of signal comparison.

15.3 Control circuitry associated with protective functions (Table 1-5)

This component of Protection Systems includes the trip coil(s) of the circuit breaker, circuit switcher or any other interrupting device. It includes the wiring from the batteries to the relays. It includes the wiring (or other signal conveyance) from every trip output to every trip coil. It includes any device needed for the correct processing of the needed trip signal to the trip coil of the interrupting device; this requirement is meant to capture inputs and outputs to and from a protective relay that are necessary for the correct operation of the protective functions. In short, every trip path must be verified; the method of verification is optional to the asset owner. An example of testing methods to accomplish this might be to verify, with a volt-meter, the existence of the proper voltage at the open contacts, the open circuited input circuit and at the trip coil(s). As every parallel trip path has similar failure modes, each trip path from relay to trip coil must be verified. Each trip coil must be tested to trip the circuit breaker (or other interrupting device) at least once. There is a requirement to operate the circuit breaker (or other interrupting device) at least once every six years as part of the complete functional test. If a suitable monitoring system is installed that verifies every parallel trip path, then the manual-intervention testing of those parallel trip paths can be eliminated; however, the actual operation of the circuit breaker must still occur at least once every six years. This six-year tripping requirement can be completed as easily as tracking the Real-time Fault-clearing operations on the circuit breaker, or tracking the trip coil(s) operation(s) during circuit breaker routine maintenance actions.

The circuit-interrupting device should not be confused with a motor-operated disconnect. The intent of this standard is to require maintenance intervals and activities on Protection Systems equipment, and not just all system isolating equipment.

It is necessary, however, to classify a device that actuates a high-speed auto-closing ground switch as an interrupting device, if this ground switch is utilized in a Protection System and forces a ground Fault to occur that then results in an expected Protection System operation to clear the forced ground Fault. The SDT believes that this is essentially a transferred-tripping device without the use of communications equipment. If this high-speed ground switch is "…designed to provide protection for the BES…" then this device needs to be treated as any other Protection System component. The control circuitry would have to be tested within 12 years, and any electromechanically operated device will have to be tested every six years. If the spring-operated ground switch can be disconnected from the solenoid triggering unit, then the solenoid triggering unit can easily be tested without the actual closing of the ground blade.

The dc control circuitry also includes each auxiliary tripping relay (94) and each lock-out relay (86) that may exist in any particular trip scheme. If the lock-out relays (86) are electromechanical type components, then they must be trip tested. The PSMT SDT considers these components to share some similarities in failure modes as electromechanical protective relays; as such, there is a six-year maximum interval between mandated maintenance tasks unless PBM is applied.

Contacts of the 86 and/or 94 that pass the trip current on to the circuit interrupting device trip coils will have to be checked as part of the 12 year requirement. Contacts of the 86 and/or 94 lock relay that operate non-BES interrupting devices are not required. Normally-open contacts that are not used to pass a trip signal and normally-closed contacts do not have to be verified. Verification of the tripping paths is the requirement.

New technology is also accommodated here; there are some tripping systems that have replaced the traditional hard-wired trip circuitry with other methods of trip-signal conveyance such as fiber-optics. It is the intent of the PSMT SDT to include this, and any other, technology that is used to convey a trip signal from a protective relay to a circuit breaker (or other interrupting device) within this category of equipment. The requirement for these systems is verification of the tripping path.

Monitoring of the control circuit integrity allows for no maintenance activity on the control circuit (excluding the requirement to operate trip coils and electromechanical lockout and/or tripping auxiliary relays). Monitoring of integrity means to monitor for continuity and/or presence of voltage on each trip path. For Ethernet or fiber-optic control systems, monitoring of integrity means to monitor communication ability between the relay and the circuit breaker.

15.3.1 Frequently Asked Questions:

Is it permissible to verify circuit breaker tripping at a different time (and interval) than when we verify the protective relays and the instrument transformers?

Yes, provided the entire Protective System is tested within the individual component's maximum allowable testing intervals.

The Protection System Maintenance Standard describes requirements for verifying the tripping of circuit breakers. What is this telling me about maintenance of circuit breakers?

Requirements in PRC-005-4 are intended to verify the integrity of tripping circuits, including the breaker trip coil, as well as the presence of auxiliary supply (usually a battery) for energizing the trip coil if a protection function operates. Beyond this, PRC-005-4 sets no requirements for verifying circuit breaker performance, or for maintenance of the circuit breaker.

How do I test each dc Control Circuit trip path, as established in Table 1-5 "Protection System Control Circuitry (Trip coils and auxiliary relays)"?

Table 1-5 specifies that each breaker trip coil and lockout relays that carry trip current to a trip coil must be operated within the specified time period. The required operations may be via targeted maintenance activities, or by documented operation of these devices for other purposes such as Fault clearing.

Are high-speed ground switch trip coils included in the dc control circuitry?

Yes. PRC-005-4 includes high-speed grounding switch trip coils within the dc control circuitry to the degree that the initiating Protection Systems are characterized as "transmission Protection Systems."

Does the control circuitry and trip coil of a non-BES breaker, tripped via a BES protection component, have to be tested per Table 1.5? (Refer to Table 3 for examples 1 and 2) Example 1: A non-BES circuit breaker that is tripped via a Protection System to which PRC-005-4 applies might be (but is not limited to) a 12.5KV circuit breaker feeding (non-black-start) radial Loads but has a trip that originates from an under-frequency (81) relay.

- The relay must be verified.
- The voltage signal to the relay must be verified.
- All of the relevant dc supply tests still apply.
- The unmonitored trip circuit between the relay and any lock-out or auxiliary relay must be verified every 12 years.
- The unmonitored trip circuit between the lock-out (or auxiliary relay) and the non-BES breaker does not have to be proven with an electrical trip.
- In the case where there is no lock-out or auxiliary tripping relay used, the trip circuit to the non-BES breaker does not have to be proven with an electrical trip.
- The trip coil of the non-BES circuit breaker does not have to be individually proven with an electrical trip.

Example 2: A Transmission Owner may have a non-BES breaker that is tripped via a Protection System to which PRC-005-4 applies, which may be (but is not limited to) a 13.8 KV circuit breaker feeding (non-black-start) radial Loads but has a trip that originates from a BES 115KV line relay.

- The relay must be verified
- The voltage signal to the relay must be verified
- All of the relevant dc supply tests still apply
- The unmonitored trip circuit between the relay and any lock-out (86) or auxiliary (94) relay must be verified every 12 years

- The unmonitored trip circuit between the lock-out (86) (or auxiliary (94)) relay and the non-BES breaker does not have to be proven with an electrical trip
- In the case where there is no lockout (86) or auxiliary (94) tripping relay used, the trip circuit to the non-BES breaker does not have to be proven with an electrical trip.
- The trip coil of the non-BES circuit breaker does not have to be individually proven with an electrical trip

Example 3: A Generator Owner may have a non-BES circuit breaker that is tripped via a Protection System to which PRC-005-4 applies, such as the generator field breaker and low-side breakers on station service/excitation transformers connected to the generator bus.

Trip testing of the generator field breaker and low side station service/excitation transformer breaker(s) via lockout or auxiliary tripping relays are not required since these breakers may be associated with radially fed loads and are not considered to be BES breakers. An example of an otherwise non-BES circuit breaker that is tripped via a BES protection component might be (but is not limited to) a 6.9kV station service transformer source circuit breaker but has a trip that originates from a generator differential (87) relay.

- The differential relay must be verified.
- The current signals to the relay must be verified.
- All of the relevant dc supply tests still apply.
- The unmonitored trip circuit between the relay and any lock-out or auxiliary relay must be verified every 12 years.
- The unmonitored trip circuit between the lock-out (or auxiliary relay) and the non-BES breaker does not have to be proven with an electrical trip.
- In the case where there is no lock-out or auxiliary tripping relay used, the trip circuit to the non-BES breaker does not have to be proven with an electrical trip.
- The trip coil of the non-BES circuit breaker does not have to be individually proven with an electrical trip.

However, it is very prudent to verify the tripping of such breakers for the integrity of the overall generation plant.

Do I have to verify operation of breaker "a" contacts or any other normally closed auxiliary contacts in the trip path of each breaker as part of my control circuit test?

Operation of normally-closed contacts does not have to be verified. Verification of the tripping paths is the requirement. The continuity of the normally closed contacts will be verified when the tripping path is verified.

15.4 Batteries and DC Supplies (Table 1-4)

The NERC definition of a Protection System is:

- Protective relays which respond to electrical quantities,
- Communications Systems necessary for correct operation of protective functions,
- Voltage and current sensing devices providing inputs to protective relays,

- Station dc supply associated with protective functions (including station batteries, battery chargers, and non-battery-based dc supply), and
- Control circuitry associated with protective functions through the trip coil(s) of the circuit breakers or other interrupting devices.

The station battery is not the only component that provides dc power to a Protection System. In the new definition for Protection System, “station batteries” are replaced with “station dc supply” to make the battery charger and dc producing stored energy devices (that are not a battery) part of the Protection System that must be maintained.

The PSMT SDT recognizes that there are several technological advances in equipment and testing procedures that allow the owner to choose how to verify that a battery string is free of open circuits. The term “continuity” was introduced into the standard to allow the owner to choose how to verify continuity of a battery set by various methods, and not to limit the owner to other conventional methods of showing continuity. Continuity, as used in Table 1-4 of the standard, refers to verifying that there is a continuous current path from the positive terminal of the station battery set to the negative terminal. Without verifying continuity of a station battery, there is no way to determine that the station battery is available to supply dc power to the station. An open battery string will be an unavailable power source in the event of loss of the battery charger.

Batteries cannot be a unique population segment of a Performance-Based Maintenance Program (PBM) because there are too many variables in the electrochemical process to completely isolate all of the performance-changing criteria necessary for using PBM on battery Systems. However, nothing precludes the use of a PBM process for any other part of a dc supply besides the batteries themselves.

15.4.1 Frequently Asked Questions:

What constitutes the station dc supply, as mentioned in the definition of Protective System?

The previous definition of Protection System includes batteries, but leaves out chargers. The latest definition includes chargers, as well as dc systems that do not utilize batteries. This revision of PRC-005-4 is intended to capture these devices that were not included under the previous definition. The station direct current (dc) supply normally consists of two components: the battery charger and the station battery itself. There are also emerging technologies that provide a source of dc supply that does not include either a battery or charger.

<u>Battery Charger</u> - The battery charger is supplied by an available ac source. At a minimum, the battery charger must be sized to charge the battery (after discharge) and supply the constant dc load. In many cases, it may be sized also to provide sufficient dc current to handle the higher energy requirements of tripping breakers and switches when actuated by the protective relays in the Protection System.

<u>Station Battery</u> - Station batteries provide the dc power required for tripping and for supplying normal dc power to the station in the event of loss of the battery charger. There are several technologies of battery that require unique forms of maintenance as established in Table 1-4.

<u>Emerging Technologies</u> - Station dc supplies are currently being developed that use other energy storage technologies besides the station battery to prevent loss of the station dc supply when ac

power is lost. Maintenance of these station dc supplies will require different kinds of tests and inspections. Table 1-4 presents maintenance activities and maximum allowable testing intervals for these new station dc supply technologies. However, because these technologies are relatively new, the maintenance activities for these station dc supplies may change over time.

What did the PSMT SDT mean by "continuity" of the dc supply?

The PSMT SDT recognizes that there are several technological advances in equipment and testing procedures that allow the owner to choose how to verify that a battery string is free of open circuits. The term "continuity" was introduced into the standard to allow the owner to choose how to verify continuity (no open circuits) of a battery set by various methods, and not to limit the owner to other conventional methods of showing continuity – lack of an open circuit. Continuity, as used in Table 1-4 of the standard, refers to verifying that there is a continuous current path from the positive terminal of the station battery set to the negative terminal (no open circuit). Without verifying continuity of a station battery, there is no way to determine that the station battery is available to supply dc power to the station. Whether it is caused from an open cell or a bad external connection, an open battery string will be an unavailable power source in the event of loss of the battery charger.

The current path through a station battery from its positive to its negative connection to the dc control circuits is composed of two types of elements. These path elements are the electrochemical path through each of its cells and all of the internal and external metallic connections and terminations of the batteries in the battery set. If there is loss of continuity (an open circuit) in any part of the electrochemical or metallic path, the battery set will not be available for service. In the event of the loss of the ac source or battery charger, the battery must be capable of supplying dc current, both for continuous dc loads and for tripping breakers and switches. Without continuity, the battery cannot perform this function.

At generating stations and large transmission stations where battery chargers are capable of handling the maximum current required by the Protection System, there are still problems that could potentially occur when the continuity through the connected battery is interrupted.

- Many battery chargers produce harmonics which can cause failure of dc power supplies in microprocessor-based protective relays and other electronic devices connected to station dc supply. In these cases, the substation battery serves as a filter for these harmonics. With the loss of continuity in the battery, the filter provided by the battery is no longer present.
- Loss of electrical continuity of the station battery will cause, in most battery chargers, regardless of the battery charger's output current capability, a delayed response in full output current from the charger. Almost all chargers have an intentional one- to two-second delay to switch from a low substation dc load current to the maximum output of the charger. This delay would cause the opening of circuit breakers to be delayed, which could violate system performance standards.

Monitoring of the station dc supply voltage will not indicate that there is a problem with the dc current path through the battery, unless the battery charger is taken out of service. At that time, a break in the continuity of the station battery current path will be revealed because there will be no voltage on the station dc circuitry. This particular test method, while proving battery continuity, may not be acceptable to all installations.

Although the standard prescribes what must be accomplished during the maintenance activity, it does not prescribe how the maintenance activity should be accomplished. There are several methods that can be used to verify the electrical continuity of the battery. These are not the only possible methods, simply a sampling of some methods:

- One method is to measure that there is current flowing through the battery itself by a simple clamp on milliamp-range ammeter. A battery is always either charging or discharging. Even when a battery is charged, there is still a measurable float charge current that can be detected to verify that there is continuity in the electrical path through the battery.
- A simple test for continuity is to remove the battery charger from service and verify that the battery provides voltage and current to the dc system. However, the behavior of the various dc-supplied equipment in the station should be considered before using this approach.
- Manufacturers of microprocessor-controlled battery chargers have developed methods for their equipment to periodically (or continuously) test for battery continuity. For example, one manufacturer periodically reduces the float voltage on the battery until current from the battery to the dc load can be measured to confirm continuity.
- Applying test current (as in some ohmic testing devices, or devices for locating dc grounds) will provide a current that when measured elsewhere in the string, will prove that the circuit is continuous.
- Internal ohmic measurements of the cells and units of lead-acid batteries (VRLA & VLA) can detect lack of continuity within the cells of a battery string; and when used in conjunction with resistance measurements of the battery's external connections, can prove continuity. Also some methods of taking internal ohmic measurements, by their very nature, can prove the continuity of a battery string without having to use the results of resistance measurements of the external connections.
- Specific gravity tests could infer continuity because without continuity there could be no charging occurring; and if there is no charging, then specific gravity will go down below acceptable levels over time.

No matter how the electrical continuity of a battery set is verified, it is a necessary maintenance activity that must be performed at the intervals prescribed by Table 1-4 to insure that the station dc supply has a path that can provide the required current to the Protection System at all times.

When should I check the station batteries to see if they have sufficient energy to perform as manufactured?

The answer to this question depends on the type of battery (valve-regulated lead-acid, vented lead-acid, or nickel-cadmium) and the maintenance activity chosen.

For example, if you have a valve-regulated lead-acid (VRLA) station battery, and you have chosen to evaluate the measured cell/unit internal ohmic values to the battery cell's baseline, you will have to perform verification at a maximum maintenance interval of no greater than every six months. While this interval might seem to be quite short, keep in mind that the six-

month interval is important for VRLA batteries; this interval provides an accumulation of data that better shows when a VRLA battery is incapable of performing as manufactured.

If, for a VRLA station battery, you choose to conduct a performance capacity test on the entire station battery as the maintenance activity, then you will have to perform verification at a maximum maintenance interval of no greater than every three calendar years.

How is a baseline established for cell/unit internal ohmic measurements?

Establishment of cell/unit internal ohmic baseline measurements should be completed when lead-acid batteries are newly installed. To ensure that the baseline ohmic cell/unit values are most indicative of the station battery's ability to perform as manufactured, they should be made at some point in time after the installation to allow the cell chemistry to stabilize after the initial freshening charge. An accepted industry practice for establishing baseline values is after six-months of installation, with the battery fully charged and in service. However, it is recommended that each owner, when establishing a baseline, should consult the battery manufacturer for specific instructions on establishing an ohmic baseline for their product, if available.

When internal ohmic measurements are taken, the same make/model test equipment should be used to establish the baseline and used for the future trending of the cells internal ohmic measurements because of variances in test equipment and the type of ohmic measurement used by different manufacturer's equipment. Keep in mind that one manufacturer's "Conductance" test equipment does not produce similar results as another manufacturer's "Conductance" test equipment, even though both manufacturers have produced "Ohmic" test equipment. Therefore, for meaningful results to an established baseline, the same make/model of instrument should be used.

For all new installations of valve-regulated lead-acid (VRLA) batteries and vented lead-acid (VLA) batteries, where trending of the cells internal ohmic measurements to a baseline are to be used to determine the ability of the station battery to perform as manufactured, the establishment of the baseline, as described above, should be followed at the time of installation to insure the most accurate trending of the cell/unit. However, often for older VRLA batteries, the owners of the station batteries have not established a baseline at installation. Also for owners of VLA batteries who want to establish a maintenance activity which requires trending of measured ohmic values to a baseline, there was typically no baseline established at installation of the station battery to trend to.

To resolve the problem of the unavailability of baseline internal ohmic measurements for the individual cell/unit of a station battery, many manufacturers of internal ohmic measurement devices have established libraries of baseline values for VRLA and VLA batteries using their testing device. Also, several of the battery manufacturers have libraries of baselines for their products that can be used to trend to. However, it is important that when using battery manufacturer-supplied data that it is verified that the baseline readings to be used were taken with the same ohmic testing device that will be used for future measurements (for example "Conductance Readings" from one manufacturer's test equipment do not correlate to "Impedance Readings" from a different manufacturer's test equipment). Although many manufacturers may have provided baseline values, which will allow trending of the internal ohmic measurements over the remaining life of a station battery, these baselines are not the actual cell/unit measurements for the battery being trended. It is important to have a baseline tailored to the station battery to more accurately use the tool of ohmic measurement trending. That more customized baseline

can only be created by following the establishment of a baseline for each cell/unit at the time of installation of the station battery.

Why determine the State of Charge?

Even though there is no present requirement to check the state of charge of a battery, it can be a very useful tool in determining the overall condition of a battery system. The following discussions are offered as a general reference.

When a battery is fully charged, the battery is available to deliver its existing capacity. As a battery is discharged, its ability to deliver its maximum available capacity is diminished. It is necessary to determine if the state of charge has dropped to an unacceptable level.

What is State of Charge and how can it be determined in a station battery?

The state of charge of a battery refers to the ratio of residual capacity at a given instant to the maximum capacity available from the battery. When a battery is fully charged, the battery is available to deliver its existing capacity. As a battery is discharged, its ability to deliver its maximum available capacity is diminished. Knowing the amount of energy left in a battery compared with the energy it had when it was fully charged gives the user an indication of how much longer a battery will continue to perform before it needs recharging.

For vented lead-acid (VLA) batteries which use accessible liquid electrolyte, a hydrometer can be used to test the specific gravity of each cell as a measure of its state of charge. The hydrometer depends on measuring changes in the weight of the active chemicals. As the battery discharges, the active electrolyte, sulfuric acid, is consumed and the concentration of the sulfuric acid in water is reduced. This, in turn, reduces the specific gravity of the solution in direct proportion to the state of charge. The actual specific gravity of the electrolyte can, therefore, be used as an indication of the state of charge of the battery. Hydrometer readings may not tell the whole story, as it takes a while for the acid to get mixed up in the cells of a VLA battery. If measured right after charging, you might see high specific gravity readings at the top of the cell, even though it is much less at the bottom. Conversely, if taken shortly after adding water to the cell, the specific gravity readings near the top of the cell will be lower than those at the bottom.

Nickel-cadmium batteries, where the specific gravity of the electrolyte does not change during battery charge and discharge, and valve-regulated lead-acid (VRLA) batteries, where the electrolyte is not accessible, cannot have their state of charge determined by specific gravity readings. For these two types of batteries, and for VLA batteries also, where another method besides taking hydrometer readings is desired, the state of charge may be determined by taking voltage and current readings at the battery terminals. The methods employed to obtain accurate readings vary for the different battery types. Manufacturers' information and IEEE guidelines can be consulted for specifics; (see IEEE 1106 Annex B for Nickel Cadmium batteries, IEEE 1188 Annex A for VRLA batteries and IEEE 450 for VLA batteries.

Why determine the Connection Resistance?

High connection resistance can cause abnormal voltage drop or excessive heating during discharge of a station battery. During periods of a high rate of discharge of the station battery, a very high resistance can cause severe damage. The maintenance requirement to verify battery terminal connection resistance in Table 1-4 is established to verify that the integrity of all battery electrical connections is acceptable. This verification includes cell-to-cell (intercell) and external

circuit terminations. Your method of checking for acceptable values of intercell and terminal connection resistance could be by individual readings, or a combination of the two. There are test methods presently that can read post termination resistances and resistance values between external posts. There are also test methods presently available that take a combination reading of the post termination connection resistance plus the intercell resistance value plus the post termination connection resistance value. Either of the two methods, or any other method, that can show if the adequacy of connections at the battery posts is acceptable.

Adequacy of the electrical terminations can be determined by comparing resistance measurements for all connections taken at the time of station battery's installation to the same resistance measurements taken at the maintenance interval chosen, not to exceed the maximum maintenance interval of Table 1-4. Trending of the interval measurements to the baseline measurements will identify any degradation in the battery connections. When the connection resistance values exceed the acceptance criteria for the connection, the connection is typically disassembled, cleaned, reassembled and measurements taken to verify that the measurements are adequate when compared to the baseline readings.

What conditions should be inspected for visible battery cells?

The maintenance requirement to inspect the cell condition of all station battery cells where the cells are visible is a maintenance requirement of Table 1-4. Station batteries are different from any other component in the Protection Station because they are a perishable product due to the electrochemical process which is used to produce dc electrical current and voltage. This inspection is a detailed visual inspection of the cells for abnormalities that occur in the aging process of the cell. In VLA battery visual inspections, some of the things that the inspector is typically looking for on the plates are signs of sulfation of the plates, abnormal colors (which are an indicator of sulfation or possible copper contamination) and abnormal conditions such as cracked grids. The visual inspection could look for symptoms of hydration that would indicate that the battery has been left in a completely discharged state for a prolonged period. Besides looking at the plates for signs of aging, all internal connections, such as the bus bar connection to each plate, and the connections to all posts of the battery need to be visually inspected for abnormalities. In a complete visual inspection for the condition of the cell the cell plates, separators and sediment space of each cell must be looked at for signs of deterioration. An inspection of the station battery's cell condition also includes looking at all terminal posts and cell-to-cell electric connections to ensure they are corrosion free. The case of the battery containing the cell, or cells, must be inspected for cracks and electrolyte leaks through cracks and the post seals.

This maintenance activity cannot be extended beyond the maximum maintenance interval of Table 1-4 by a Performance-Based Maintenance Program (PBM) because of the electrochemical aging process of the station battery, nor can there be any monitoring associated with it because there must be a visual inspection involved in the activity. A remote visual inspection could possibly be done, but its interval must be no greater than the maximum maintenance interval of Table 1-4.

Why is it necessary to verify the battery string can perform as manufactured? I only care that the battery can trip the breaker, which means that the battery can perform as designed. I oversize my batteries so that even if the battery cannot perform as manufactured, it can still trip my breakers.

The fundamental answer to this question revolves around the concept of battery performance "as designed" vs. battery performance "as manufactured." The purpose of the various sections of Table 1-4 of this standard is to establish requirements for the Protection System owner to maintain the batteries, to ensure they will operate the equipment when there is an incident that requires dc power, and ensure the batteries will continue to provide adequate service until at least the next maintenance interval. To meet these goals, the correct battery has to be properly selected to meet the design parameters, and the battery has to deliver the power it was manufactured to provide.

When testing batteries, it may be difficult to determine the original design (i.e., load profile) of the dc system. This standard is not intended as a design document, and requirements relating to design are, therefore, not included.

Where the dc load profile is known, the best way to determine if the system will operate as designed is to conduct a service test on the battery. However, a service test alone might not fully determine if the battery is healthy. A battery with 50% capacity may be able to pass a service test, but the battery would be in a serious state of deterioration and could fail at some point in the near future.

To ensure that the battery will meet the required load profile and continue to meet the load profile until the next maintenance interval, the installed battery must be sized correctly (i.e., a correct design), and it must be in a good state of health. Since the design of the dc system is not within the scope of the standard, the only consistent and reliable method to ensure that the battery is in a good state of health is to confirm that it can perform as manufactured. If the battery can perform as manufactured and it has been designed properly, the system should operate properly until the next maintenance interval.

How do I verify the battery string can perform as manufactured?

Optimally, actual battery performance should be verified against the manufacturer's rating curves. The best practice for evaluating battery performance is via a performance test. However, due to both logistical and system reliability concerns, some Protection System owners prefer other methods to determine if a battery can perform as manufactured. There are several battery parameters that can be evaluated to determine if a battery can perform as manufactured. Ohmic measurements and float current are two examples of parameters that have been reported to assist in determining if a battery string can perform as manufactured.

The evaluation of battery parameters in determining battery health is a complex issue, and is not an exact science. This standard gives the user an opportunity to utilize other measured parameters to determine if the battery can perform as manufactured. It is the responsibility of the Protection System owner, however, to maintain a documented process that demonstrates the chosen parameter(s) and associated methodology used to determine if the battery string can perform as manufactured.

Whatever parameters are used to evaluate the battery (ohmic measurements, float current, float voltages, temperature, specific gravity, performance test, or combination thereof), the goal is to determine the value of the measurement (or the percentage change) at which the battery fails to perform as manufactured, or the point where the battery is deteriorating so rapidly that it will not perform as manufactured before the next maintenance interval.

This necessitates the need for establishing and documenting a baseline. A baseline may be required of every individual cell, a particular battery installation, or a specific make, model, or size of a cell. Given a consistent cell manufacturing process, it may be possible to establish a baseline number for the cell (make/model/type) and, therefore, a subsequent baseline for every installation would not be necessary. However, future installations of the same battery types should be spot-checked to ensure that your baseline remains applicable.

Consistent testing methods by trained personnel are essential. Moreover, it is essential that these technicians utilize the same make/model of ohmic test equipment each time readings are taken in order to establish a meaningful and accurate trend line against the established baseline. The type of probe and its location (post, connector, etc.) for the reading need to be the same for each subsequent test. The room temperature should be recorded with the readings for each test as well. Care should be taken to consider any factors that might lead a trending program to become invalid.

Float current along with other measureable parameters can be used in lieu of or in concert with ohmic measurement testing to measure the ability of a battery to perform as manufactured. The key to using any of these measurement parameters is to establish a baseline and the point where the reading indicates that the battery will not perform as manufactured.

The establishment of a baseline may be different for various types of cells and for different types of installations. In some cases, it may be possible to obtain a baseline number from the battery manufacturer, although it is much more likely that the baseline will have to be established after the installation is complete. To some degree, the battery may still be "forming" after installation; consequently, determining a stable baseline may not be possible until several months after the battery has been in service.

The most important part of this process is to determine the point where the ohmic reading (or other measured parameter(s)) indicates that the battery cannot perform as manufactured. That point could be an absolute number, an absolute change, or a percentage change of an established baseline.

Since there are no universally-accepted repositories of this information, the Protection System owner will have to determine the value/percentage where the battery cannot perform as manufactured (heretofore referred to as a failed cell). This is the most difficult and important part of the entire process.

To determine the point where the battery fails to perform as manufactured, it is helpful to have a history of a battery type, if the data includes the parameter(s) used to evaluate the battery's ability to perform as manufactured against the actual demonstrated performance/capacity of a battery/cell.

For example, when an ohmic reading has been recorded that the user suspects is indicating a failed cell, a performance test of that cell (or string) should be conducted in order to prove/quantify that the cell has failed. Through this process, the user needs to determine the ohmic value at which the performance of the cell has dropped below 80% of the manufactured, rated performance. It is likely that there may be a variation in ohmic readings that indicates a failed cell (possibly significant). It is prudent to use the most conservative values to determine the point at which the cell should be marked for replacement. Periodically, the user should demonstrate that an "adequate" ohmic reading equates to an adequate battery performance (>80% of capacity).

Similarly, acceptance criteria for "good" and "failed" cells should be established for other parameters such as float current, specific gravity, etc., if used to determine the ability of a battery to function as designed.

What happens if I change the make/model of ohmic test equipment after the battery has been installed for a period of time?

If a user decides to switch testers, either voluntarily or because the equipment is not supported/sold any longer, the user may have to establish a new base line and new parameters that indicate when the battery no longer performs as manufactured. The user always has a choice to perform a capacity test in lieu of establishing new parameters.

What are some of the differences between lead-acid and nickel-cadmium batteries?

There is a marked difference in the aging process of lead acid and nickel-cadmium station batteries. The difference in the aging process of these two types of batteries is chiefly due to the electrochemical process of the battery type. Aging and eventual failure of lead acid batteries is due to expansion and corrosion of the positive grid structure, loss of positive plate active material, and loss of capacity caused by physical changes in the active material of the positive plates. In contrast, the primary failure of nickel-cadmium batteries is due to the gradual linear aging of the active materials in the plates. The electrolyte of a nickel-cadmium battery only facilitates the chemical reaction (it functions only to transfer ions between the positive and negative plates), but is not chemically altered during the process like the electrolyte of a lead acid battery. A lead acid battery experiences continued corrosion of the positive plate and grid structure throughout its operational life while a nickel-cadmium battery does not.

Changes to the properties of a lead acid battery when periodically measured and trended to a baseline, can indicate aging of the grid structure, positive plate deterioration, or changes in the active materials in the plate.

Because of the clear differences in the aging process of lead acid and nickel-cadmium batteries, there are no significantly measurable properties of the nickel-cadmium battery that can be measured at a periodic interval and trended to determine aging. For this reason, Table 1-4(c) (Protection System Station dc supply Using nickel-cadmium [NiCad] Batteries) only specifies one minimum maintenance activity and associated maximum maintenance interval necessary to verify that the station battery can perform as manufactured by evaluating cell/unit measurements indicative of battery performance against the station battery baseline. This maintenance activity is to conduct a performance or modified performance capacity test of the entire battery bank.

Why in Table 1-4 of PRC-005-4 is there a maintenance activity to inspect the structural intergrity of the battery rack?

The purpose of this inspection is to verify that the battery rack is correctly installed and has no deterioration that could weaken its structural integrity.
Because the battery rack is specifically manufactured for the battery that is mounted on it, weakening of its structural members by rust or corrosion can physically jeopardize the battery.

What is required to comply with the "Unintentional dc Grounds" requirement?

In most cases, the first ground that appears on a battery is not a problem. It is the unintentional ground that appears on the opposite pole that becomes problematic. Even then many systems

are designed to operate favorably under some unintentional DC ground situations. It is up to the owner of the Protection System to determine if corrective actions are needed on detected unintentional DC grounds. The standard merely requires that a check be made for the existence of Unintentional DC Grounds. Obviously, a “check-off” of some sort will have to be devised by the inspecting entity to document that a check is routinely done for Unintentional DC Grounds because of the possible consequences to the Protection System.

Where the standard refers to “all cells,” is it sufficient to have a documentation method that refers to “all cells,” or do we need to have separate documentation for every cell? For example, do I need 60 individual documented check-offs for good electrolyte level, or would a single check-off per bank be sufficient?

A single check-off per battery bank is sufficient for documentation, as long as the single check-off attests to checking all cells/units.

Does this standard refer to Station batteries or all batteries; for example, Communications Site Batteries?

This standard refers to Station Batteries. The drafting team does not believe that the scope of this standard refers to communications sites. The batteries covered under PRC-005-4 are the batteries that supply the trip current to the trip coils of the interrupting devices that are a part of the Protection System. The SDT believes that a loss of power to the communications systems at a remote site would cause the communications systems associated with protective relays to alarm at the substation. At this point, the corrective actions can be initiated.

What are cell/unit internal ohmic measurements?

With the introduction of Valve-Regulated Lead-Acid (VRLA) batteries to station dc supplies in the 1980’s several of the standard maintenance tools that are used on Vented Lead-Acid (VLA) batteries were unable to be used on this new type of lead-acid battery to determine its state of health. The only tools that were available to give indication of the health of these new VRLA batteries were voltage readings of the total battery voltage, the voltage of the individual cells and periodic discharge tests.

In the search for a tool for determining the health of a VRLA battery several manufacturers studied the electrical model of a lead acid battery’s current path through its cell. The overall battery current path consists of resistance and inductive and capacitive reactance. The inductive reactance in the current path through the battery is so minuscule when compared to the huge capacitive reactance of the cells that it is often ignored in most circuit models of the battery cell. Taking the basic model of a battery cell manufacturers of battery test equipment have developed and marketed testing devices to take measurements of the current path to detect degradation in the internal path through the cell.

In the battery industry, these various types of measurements are referred to as ohmic measurements. Terms used by the industry to describe ohmic measurements are ac conductance, ac impedance, and dc resistance. They are defined by the test equipment providers and IEEE and refer to the method of taking ohmic measurements of a lead acid battery. For example, in one manufacturer’s ac conductance equipment measurements are taken by applying a voltage of a known frequency and amplitude across a cell or battery unit and observing the ac current flow it produces in response to the voltage. A manufacturer of an ac impedance meter measures ac current of a known frequency and amplitude that is passed through the whole battery string and determines the impedances of each cell or unit by measuring the resultant ac

voltage drop across them. On the other hand, dc resistance of a cell is measured by a third manufacturer's equipment by applying a dc load across the cell or unit and measuring the step change in both the voltage and current to calculate the internal dc resistance of the cell or unit.

It is important to note that because of the rapid development of the market for ohmic measurement devices, there were no standards developed or used to mandate the test signals used in making ohmic measurements. Manufacturers using proprietary methods and applying different frequencies and magnitudes for their signals have developed a diversity of measurement devices. This diversity in test signals coupled with the three different types of ohmic measurements techniques (impedance conductance and resistance) make it impossible to always get the same ohmic measurement for a cell with different ohmic measurement devices. However, IEEE has recognized the great value for choosing one device for ohmic measurement, no matter who makes it or the method to calculate the ohmic measurement. The only caution given by IEEE and the battery manufacturers is that when trending the cells of a lead acid station battery consistent ohmic measurement devices should be used to establish the baseline measurement and to trend the battery set for its entire life.

For VRLA batteries both IEEE Standard 1188 (Maintenance, Testing and Replacement of VRLA Batteries) and IEEE Standard 1187 (Installation Design and Installation of VRLA Batteries) recognize the importance of the maintenance activity of establishing a baseline for "cell/unit internal ohmic measurements (impedance, conductance and resistance)" and trending them at frequent intervals over the life of the battery. There are extensive discussions about the need for taking these measurements in these standards. IEEE Standard 1188 requires taking internal ohmic values as described in Annex C4 during regular inspections of the station battery. For VRLA batteries IEEE Standard 1188 in talking about the necessity of establishing a baseline and trending it over time says, "…depending on the degree of change a performance test, cell replacement or other corrective action may be necessary…" (IEEE std 1188-2005, C.4 page 18).

For VLA batteries IEEE Standard 484 (Installation of VLA batteries) gives several guidelines about establishing baseline measurements on newly installed lead acid stationary batteries. The standard also discusses the need to look for significant changes in the ohmic measurements, the caution that measurement data will differ with each type of model of instrument used, and lists a number of factors that affect ohmic measurements.

At the beginning of the 21st century, EPRI conducted a series of extensive studies to determine the relationship of internal ohmic measurements to the capacity of a lead acid battery cell. The studies indicated that internal ohmic measurements were in fact a good indicator of a lead acid battery cell's capacity, but because users often were only interested in the total station battery capacity and the technology does not precisely predict overall battery capacity, if a user only needs "an accurate measure of the overall battery capacity," they should "perform a battery capacity test."

Prior to the EPRI studies some large and small companies which owned and maintained station dc supplies in NERC Protection Systems developed maintenance programs where trending of ohmic measurements of cells/units of the station's battery became the maintenance activity for determining if the station battery could perform as manufactured. By evaluation of the trending of the ohmic measurements over time, the owner could track the performance of the individual components of the station battery and determine if a total station battery or components of it

required capacity testing, removal, replacement or in many instances replacement of the entire station battery. By taking this condition based approach these owners have eliminated having to perform capacity testing at prescribed intervals to determine if a battery needs to be replaced and are still able to effectively determine if a station battery can perform as manufactured.

My VRLA batteries have multiple-cells within an individual battery jar (or unit); how am I expected to comply with the cell-to-cell ohmic measurement requirements on these units that I cannot get to?

Measurement of cell/unit (not all batteries allow access to "individual cells" some "units" or jars may have multiple cells within a jar) internal ohmic values of all types of lead acid batteries where the cells of the battery are not visible is a station dc supply maintenance activity in Table 1-4. In cases where individual cells in a multi-cell unit are inaccessible, an ohmic measurement of the entire unit may be made.

I have a concern about my batteries being used to support additional auxiliary loads beyond my protection control systems in a generation station. Is ohmic measurement testing sufficient for my needs?

While this standard is focused on addressing requirements for Protection Systems, if batteries are used to service other load requirements beyond that of Protection Systems (e.g. pumps, valves, inverter loads), the functional entity may consider additional testing to confirm that the capacity of the battery is sufficient to support all loads.

Why verify voltage?

There are two required maintenance activities associated with verification of dc voltages in Table 1-4. These two required activities are to verify station dc supply voltage and float voltage of the battery charger, and have different maximum maintenance intervals. Both of these voltage verification requirements relate directly to the battery charger maintenance.

The verification of the dc supply voltage is simply an observation of battery voltage to prove that the charger has not been lost or is not malfunctioning; a reading taken from the battery charger panel meter or even SCADA values of the dc voltage could be some of the ways that one could satisfy the requirements. Low battery voltage below float voltage indicates that the battery may be on discharge and, if not corrected, the station battery could discharge down to some extremely low value that will not operate the Protection System. High voltage, close to or above the maximum allowable dc voltage for equipment connected to the station dc supply indicates the battery charger may be malfunctioning by producing high dc voltage levels on the Protection System. If corrective actions are not taken to bring the high voltage down, the dc power supplies and other electronic devices connected to the station dc supply may be damaged. The maintenance activity of verifying the float voltage of the battery charger is not to prove that a charger is lost or producing high voltages on the station dc supply, but rather to prove that the charger is properly floating the battery within the proper voltage limits. As above, there are many ways that this requirement can be met.

Why check for the electrolyte level?

In vented lead-acid (VLA) and nickel-cadmium (NiCad) batteries the visible electrolyte level must be checked as one of the required maintenance activities that must be performed at an interval that is equal to or less than the maximum maintenance interval of Table 1-4. Because the electrolyte level in valve-regulated lead-acid (VRLA) batteries cannot be observed, there is no maintenance activity listed in Table 1-4 of the standard for checking the electrolyte level. Low

electrolyte level of any cell of a VLA or NiCad station battery is a condition requiring correction. Typically, the electrolyte level should be returned to an acceptable level for both types of batteries (VLA and NiCad) by adding distilled or other approved-quality water to the cell.

Often people confuse the interval for watering all cells required due to evaporation of the electrolyte in the station battery cells with the maximum maintenance interval required to check the electrolyte level. In many of the modern station batteries, the jar containing the electrolyte is so large with the band between the high and low electrolyte level so wide that normal evaporation which would require periodic watering of all cells takes several years to occur. However, because loss of electrolyte due to cracks in the jar, overcharging of the station battery, or other unforeseen events can cause rapid loss of electrolyte; the shorter maximum maintenance intervals for checking the electrolyte level are required. A low level of electrolyte in a VLA battery cell which exposes the tops of the plates can cause the exposed portion of the plates to accelerated sulfation resulting in loss of cell capacity. Also, in a VLA battery where the electrolyte level goes below the end of the cell withdrawal tube or filling funnel, gasses can exit the cell by the tube instead of the flame arrester and present an explosion hazard.

What are the parameters that can be evaluated in Tables 1-4(a) and 1-4(b)?

The most common parameter that is periodically trended and evaluated by industry today to verify that the station battery can perform as manufactured is internal ohmic cell/unit measurements.

In the mid-1990s, several large and small utilities began developing maintenance and testing programs for Protection System station batteries using a condition based maintenance approach of trending internal ohmic measurements to each station battery cell's baseline value. Battery owners use the data collected from this maintenance activity to determine (1) when a station battery requires a capacity test (instead of performing a capacity test on a predetermined, prescribed interval), (2) when an individual cell or battery unit should be replaced, or (3) based on the analysis of the trended data, if the station battery should be replaced without performing a capacity test.

Other examples of measurable parameters that can be periodically trended and evaluated for lead acid batteries are cell voltage, float current, connection resistance. However, periodically trending and evaluating cell/unit Ohmic measurements are the most common battery/cell parameters that are evaluated by industry to verify a lead acid battery string can perform as manufactured.

Why does it appear that there are two maintenance activities in Table 1-4(b) (for VRLA batteries) that appear to be the same activity and have the same maximum maintenance interval?

There are two different and distinct reasons for doing almost the same maintenance activity at the same interval for valve-regulated lead-acid (VRLA) batteries. The first similar activity for VRLA batteries (Table 1-4(b)) that has the same maximum maintenance interval is to "measure battery cell/unit internal ohmic values." Part of the reason for this activity is because the visual inspection of the cell condition is unavailable for VRLA batteries. Besides the requirement to measure the internal ohmic measurements of VRLA batteries to determine the internal health of the cell, the maximum maintenance interval for this activity is significantly shorter than the interval for vented lead-acid (VLA) due to some unique failure modes for VRLA batteries. Some

of the potential problems that VRLA batteries are susceptible to that do not affect VLA batteries are thermal runaway, cell dry-out, and cell reversal when one cell has a very low capacity.

The other similar activity listed in Table 1-4(b) is "…verify that the station battery can perform as manufactured by evaluating the measured cell/unit measurements indicative of battery performance (e.g. internal ohmic values) against the station battery baseline." This activity allows an owner the option to choose between this activity with its much shorter maximum maintenance interval or the longer maximum maintenance interval for the maintenance activity to "Verify that the station battery can perform as manufactured by conducting a performance or modified performance capacity test of the entire battery bank."

For VRLA batteries, there are two drivers for internal ohmic readings. The first driver is for a means to trend battery life. Trending against the baseline of VRLA cells in a battery string is essential to determine the approximate state of health of the battery. Ohmic measurement testing may be used as the mechanism for measuring the battery cells. If all the cells in the string exhibit a consistent trend line and that trend line has not risen above a specific deviation (e.g. 30%) over baseline for impedance tests or below baseline for conductance tests, then a judgment can be made that the battery is still in a reasonably good state of health and able to 'perform as manufactured.' It is essential that the specific deviation mentioned above is based on data (test or otherwise) that correlates the ohmic readings for a specific battery/tester combination to the health of the battery. This is the intent of the "perform **as** manufactured six-month test" at Row 4 on Table 1-4b.

The second big driver is VRLA batteries tendency for thermal runaway. This is the intent of the "thermal runaway test" at Row 2 on Table 1-4b. In order to detect a cell in thermal runaway, you need not necessarily have a formal trending program. When a single cell/unit changes significantly or significantly varies from the other cells (e.g. a doubling of resistance/impedance or a 50% decrease in conductance), there is a high probability that the cell/unit/string needs to be replaced as soon as possible. In other words, if the battery is 10 years old and all the cells have approached a significant change in ohmic values over baseline, then you have a battery which is approaching end of life. You need to get ready to buy a new battery, but you do not have to worry about an impending catastrophic failure. On the other hand, if the battery is five years old and you have one cell that has a markedly different ohmic reading than all the other cells, then you need to be worried that this cell is susceptible to thermal runaway. If the float (charging) current has risen significantly and the ohmic measurement has increased/decreased as described above then concern of catastrophic failure should trigger attention for corrective action.

If an entity elects to use a capacity test rather than a cell ohmic value trending program, this does not eliminate the need to be concerned about thermal runaway – the entity still needs to do the six-month readings and look for cells which are outliers in the string but they need not trend results against the factory/as new baseline. Some entities will not mind the extra administrative burden of having the ongoing trending program against baseline - others would rather just do the capacity test and not have to trend the data against baseline. Nonetheless, all entities must look for ohmic outliers on a six-month basis.

It is possible to accomplish both tasks listed (trend testing for capability and testing for thermal runaway candidates) with the very same ohmic test. It becomes an analysis exercise of watching the trend from baselines and watching for the oblique cell measurement.

In table 1-4(f) (Exclusions for Protection System Station dc Supply Monitoring Devices and Systems), must all component attributes listed in the table be met before an exclusion can be granted for a maintenance activity?

Table 1-4(f) was created by the drafting team to allow Protection System dc supply owners to obtain exclusions from periodic maintenance activities by using monitoring devices. The basis of the exclusions granted in the table is that the monitoring devices must incorporate the monitoring capability of microprocessor based components which perform continuous self-monitoring. For failure of the microprocessor device used in dc supply monitoring, the self-checking routine in the microprocessor must generate an alarm which will be reported within 24 hours of device failure to a location where corrective action can be initiated.

Table 1-4(f) lists 8 component attributes along with a specific periodic maintenance activity associated with each of the 8 attributes listed. If an owner of a station dc supply wants to be excluded from periodically performing one of the 8 maintenance activities listed in table 1-4(f), the owner must have evidence that the monitoring and alarming component attributes associated with the excluded maintenance activity are met by the self-checking microprocessor based device with the specific component attribute listed in the table 1-4(f).

For example if an owner of a VLA station battery does not want to "verify station dc supply voltage" every "4 calendar months" (see table 1-4(a)), the owner can install a monitoring and alarming device "with high and low voltage monitoring and alarming of the battery charger voltage to detect charger overvoltage and charger failure" and "no periodic verification of station dc supply voltage is required" (see table 1-4(f) first row). However, if for the same Protection System discussed above, the owner does not install "electrolyte level monitoring and alarming in every cell" and "unintentional dc ground monitoring and alarming" (see second and third rows of table 1-4(f)), the owner will have to "inspect electrolyte level and for unintentional grounds" every "4 calendar months" (see table 1-4(a)).

15.5 Associated communications equipment (Table 1-2)

The equipment used for tripping in a communications-assisted trip scheme is a vital piece of the trip circuit. Remote action causing a local trip can be thought of as another parallel trip path to the trip coil that must be tested. Besides the trip output and wiring to the trip coil(s), there is also a communications medium that must be maintained. Newer technologies now exist that achieve communications-assisted tripping without the conventional wiring practices of older technology. For example, older technologies may have included Frequency Shift Key methods. This technology requires that guard and trip levels be maintained. The actual tripping path(s) to the trip coil(s) may be tested as a parallel trip path within the dc control circuitry tests. Emerging technologies transfer digital information over a variety of carrier mediums that are then interpreted locally as trip signals. The requirements apply to the communicated signal needed for the proper operation of the protective relay trip logic or scheme. Therefore, this standard is applied to equipment used to convey both trip signals (permissive or direct) and block signals.

It was the intent of this standard to require that a test be performed on any communications-assisted trip scheme, regardless of the vintage of technology. The essential element is that the tripping (or blocking) occurs locally when the remote action has been asserted; or that the tripping (or blocking) occurs remotely when the local action is asserted. Note that the required testing can still be done within the concept of testing by overlapping segments. Associated communications equipment can be (but is not limited to) testing at other times and different frequencies as the protective relays, the individual trip paths and the affected circuit interrupting devices.

Some newer installations utilize digital signals over fiber-optics from the protective relays in the control house to the circuit interrupting device in the yard. This method of tripping the circuit breaker, even though it might be considered communications, must be maintained per the dc control circuitry maintenance requirements.

15.5.1 Frequently Asked Questions:

What are some examples of mechanisms to check communications equipment functioning?

For unmonitored Protection Systems, various types of communications systems will have different facilities for on-site integrity checking to be performed at least every four months during a substation visit. Some examples are, but not limited to:

- On-off power-line carrier systems can be checked by performing a manual carrier keying test between the line terminals, or carrier check-back test from one terminal.
- Systems which use frequency-shift communications with a continuous guard signal (over a telephone circuit, analog microwave system, etc.) can be checked by observing for a loss-of-guard indication or alarm. For frequency-shift power-line carrier systems, the guard signal level meter can also be checked.
- Hard-wired pilot wire line Protection Systems typically have pilot-wire monitoring relays that give an alarm indication for a pilot wire ground or open pilot wire circuit loop.
- Digital communications systems typically have a data reception indicator or data error indicator (based on loss of signal, bit error rate, or frame error checking).

For monitored Protection Systems, various types of communications systems will have different facilities for monitoring the presence of the communications channel, and activating alarms that can be monitored remotely. Some examples are, but not limited to:

- On-off power-line carrier systems can be shown to be operational by automated periodic power-line carrier check-back tests with remote alarming of failures.
- Systems which use a frequency-shift communications with a continuous guard signal (over a telephone circuit, analog microwave system, etc.) can be remotely monitored with a loss-of-guard alarm or low signal level alarm.
- Hard-wired pilot wire line Protection Systems can be monitored by remote alarming of pilot-wire monitoring relays.
- Digital communications systems can activate remotely monitored alarms for data reception loss or data error indications.
- Systems can be queried for the data error rates.

For the highest degree of monitoring of Protection Systems, the communications system must monitor all aspects of the performance and quality of the channel that show it meets the design performance criteria, including monitoring of the channel interface to protective relays.

- In many communications systems signal quality measurements, including signal-to-noise ratio, received signal level, reflected transmitter power or standing wave ratio, propagation delay, and data error rates are compared to alarm limits. These alarms are connected for remote monitoring.
- Alarms for inadequate performance are remotely monitored at all times, and the alarm communications system to the remote monitoring site must itself be continuously

monitored to assure that the actual alarm status at the communications equipment location is continuously being reflected at the remote monitoring site.

What is needed for the four-month inspection of communications-assisted trip scheme equipment?

The four-month inspection applies to unmonitored equipment. An example of compliance with this requirement might be, but is not limited to:

With each site visit, check that the equipment is free from alarms; check any metered signal levels, and that power is still applied. While this might be explicit for a particular type of equipment (i.e., FSK equipment), the concept should be that the entity verify that the communications equipment that is used in a Protection System is operable through a cursory inspection and site visit. This site visit can be eliminated on this particular example if the FSK equipment had a monitored alarm on Loss of Guard. Blocking carrier systems with auto checkbacks will present an alarm when the channel fails allowing a visual indication. With no auto checkback, the channel integrity will need to be verified by a manual checkback or a two ended signal check. This check could also be eliminated by bring the auto checkback failure alarm to the monitored central location.

Does a fiber optic I/O scheme used for breaker tripping or control within a station, for example - transmitting a trip signal or control logic between the control house and the breaker control cabinet, constitute a communications system?

This equipment is presently classified as being part of the Protection System control circuitry and tested per the portions of Table 1 applicable to "Protection System Control Circuitry", rather than those portions of the table applicable to communications equipment.

What is meant by "Channel" and "Communications Systems" in Table 1-2?

The transmission of logic or data from a relay in one station to a relay in another station for use in a pilot relay scheme will require a communications system of some sort. Typical relay communications systems use fiber optics, leased audio channels, power line carrier, and microwave. The overall communications system includes the channel and the associated communications equipment.

This standard refers to the "channel" as the medium between the transmitters and receivers in the relay panels such as a leased audio or digital communications circuit, power line and power line carrier auxiliary equipment, and fiber. The dividing line between the channel and the associated communications equipment is different for each type of media.

Examples of the Channel:

- Power Line Carrier (PLC) - The PLC channel starts and ends at the PLC transmitter and receiver output unless there is an internal hybrid. The channel includes the external hybrids, tuners, wave traps and the power line itself.
- Microwave –The channel includes the microwave multiplexers, radios, antennae and associated auxiliary equipment. The audio tone and digital transmitters and receivers in the relay panel are the associated communications equipment.
- Digital/Audio Circuit – The channel includes the equipment within and between the substations. The associated communications equipment includes the relay panel transmitters and receivers and the interface equipment in the relays.

- Fiber Optic – The channel starts at the fiber optic connectors on the fiber distribution panel at the local station and goes to the fiber optic distribution panel at the remote substation. The jumpers that connect the relaying equipment to the fiber distribution panel and any optical-electrical signal format converters are the associated communications equipment

Figure 1-2, A-1 and A-2 at the end of this document show good examples of the communications channel and the associated communications equipment.

In Table 1-2, the Maintenance Activities section of the Protection System Communications Equipment and Channels refers to the quality of the channel meeting "performance criteria." What is meant by performance criteria?

Protection System communications channels must have a means of determining if the channel and communications equipment is operating normally. If the channel is not operating normally, an alarm will be indicated. For unmonitored systems, this alarm will probably be on the panel. For monitored systems, the alarm will be transmitted to a remote location.

Each entity will have established a nominal performance level for each Protection System communications channel that is consistent with proper functioning of the Protection System. If that level of nominal performance is not being met, the system will go into alarm. Following are some examples of Protection System communications channel performance measuring:

- For direct transfer trip using a frequency shift power line carrier channel, a guard level monitor is part of the equipment. A normal receive level is established when the system is calibrated and if the signal level drops below an established level, the system will indicate an alarm.

- An on-off blocking signal over power line carrier is used for directional comparison blocking schemes on transmission lines. During a Fault, block logic is sent to the remote relays by turning on a local transmitter and sending the signal over the power line to a receiver at the remote end. This signal is normally off so continuous levels cannot be checked. These schemes use check-back testing to determine channel performance. A predetermined signal sequence is sent to the remote end and the remote end decodes this signal and sends a signal sequence back. If the sending end receives the correct information from the remote terminal, the test passes and no alarm is indicated. Full power and reduced power tests are typically run. Power levels for these tests are determined at the time of calibration.

- Pilot wire relay systems use a hardwire communications circuit to communicate between the local and remote ends of the protective zone. This circuit is monitored by circulating a dc current between the relay systems. A typical level may be 1 mA. If the level drops below the setting of the alarm monitor, the system will indicate an alarm.

- Modern digital relay systems use data communications to transmit relay information to the remote end relays. An example of this is a line current differential scheme commonly used on transmission lines. The protective relays communicate current magnitude and phase information over the communications path to determine if the Fault is located in

the protective zone. Quantities such as digital packet loss, bit error rate and channel delay are monitored to determine the quality of the channel. These limits are determined and set during relay commissioning. Once set, any channel quality problems that fall outside the set levels will indicate an alarm.

The previous examples show how some protective relay communications channels can be monitored and how the channel performance can be compared to performance criteria established by the entity. This standard does not state what the performance criteria will be; it just requires that the entity establish nominal criteria so Protection System channel monitoring can be performed.

How is the performance criteria of Protection System communications equipment involved in the maintenance program?

An entity determines the acceptable performance criteria, depending on the technology implemented. If the communications channel performance of a Protection System varies from the pre-determined performance criteria for that system, then these results should be investigated and resolved.

How do I verify the A/D converters of microprocessor-based relays?

There are a variety of ways to do this. Two examples would be: using values gathered via data communications and automatically comparing these values with values from other sources, or using groupings of other measurements (such as vector summation of bus feeder currents) for comparison. Many other methods are possible.

15.6 Alarms (Table 2)

In addition to the tables of maintenance for the components of a Protection System, there is an additional table added for alarms. This additional table was added for clarity. This enabled the common alarm attributes to be consolidated into a single spot, and, thus, make it easier to read the Tables 1-1 through 1-5, Table 3, and Table 4. The alarms need to arrive at a site wherein a corrective action can be initiated. This could be a control room, operations center, etc. The alarming mechanism can be a standard alarming system or an auto-polling system; the only requirement is that the alarm be brought to the action-site within 24 hours. This effectively makes manned-stations equivalent to monitored stations. The alarm of a monitored point (for example a monitored trip path with a lamp) in a manned-station now makes that monitored point eligible for monitored status. Obviously, these same rules apply to a non-manned-station, which is that if the monitored point has an alarm that is auto-reported to the operations center (for example) within 24 hours, then it too is considered monitored.

15.6.1 Frequently Asked Questions:

Why are there activities defined for varying degrees of monitoring a Protection System component when that level of technology may not yet be available?

There may already be some equipment available that is capable of meeting the highest levels of monitoring criteria listed in the Tables. However, even if there is no equipment available today that can meet this level of monitoring the standard establishes the necessary requirements for when such equipment becomes available. By creating a roadmap for development, this provision makes the standard technology neutral. The Standard Drafting Team wants to avoid the need to revise the standard in a few years to accommodate technology advances that may be coming to the industry.

Does a fail-safe "form b" contact that is alarmed to a 24/7 operation center classify as an alarm path with monitoring?

If the fail-safe "form-b" contact that is alarmed to a 24/7 operation center causes the alarm to activate for failure of any portion of the alarming path from the alarm origin to the 24/7 operations center, then this can be classified as an alarm path with monitoring.

15.7 Distributed UFLS and Distributed UVLS Systems (Table 3)

Distributed UFLS and distributed UVLS systems have their maintenance activities documented in Table 3 due to their distributed nature allowing reduced maintenance activities and extended maximum maintenance intervals. Relays have the same maintenance activities and intervals as Table 1-1. Voltage and current-sensing devices have the same maintenance activity and interval as Table 1-3. DC systems need only have their voltage read at the relay every 12 years. Control circuits have the following maintenance activities every 12 years:

- Verify the trip path between the relay and lock-out and/or auxiliary tripping device(s).
- Verify operation of any lock-out and/or auxiliary tripping device(s) used in the trip circuit.
- No verification of trip path required between the lock-out (and/or auxiliary tripping device) and the non-BES interrupting device.
- No verification of trip path required between the relay and trip coil for circuits that have no lock-out and/or auxiliary tripping device(s).
- No verification of trip coil required.

No maintenance activity is required for associated communication systems for distributed UFLS and distributed UVLS schemes.

Non-BES interrupting devices that participate in a distributed UFLS or distributed UVLS scheme are excluded from the tripping requirement, and part of the control circuit test requirement; however, the part of the trip path control circuitry between the Load-Shed relay and lock-out or auxiliary tripping relay must be tested at least once every 12 years. In the case where there is no lock-out or auxiliary tripping relay used in a distributed UFLS or UVLS scheme which is not part of the BES, there is no control circuit test requirement. There are many circuit interrupting devices in the distribution system that will be operating for any given under-frequency event that requires tripping for that event. A failure in the tripping action of a single distributed system circuit breaker (or non-BES equipment interruption device) will be far less significant than, for example, any single transmission Protection System failure, such as a failure of a bus differential lock-out relay. While many failures of these distributed system circuit breakers (or non-BES equipment interruption device) could add up to be significant, it is also believed that many circuit breakers are operated often on just Fault clearing duty; and, therefore, these circuit breakers are operated at least as frequently as any requirements that appear in this standard.

There are times when a Protection System component will be used on a BES device, as well as a non-BES device, such as a battery bank that serves both a BES circuit breaker and a non-BES interrupting device used for UFLS. In such a case, the battery bank (or other Protection System component) will be subject to the Tables of the standard because it is used for the BES.

15.7.1 Frequently Asked Questions:

The standard reaches further into the distribution system than we would like for UFLS and UVLS

While UFLS and UVLS equipment are located on the distribution network, their job is to protect the Bulk Electric System. This is not beyond the scope of NERC's 215 authority.

FPA section 215(a) definitions section defines bulk power system as: "(A) facilities and control Systems necessary for operating an interconnected electric energy transmission network (or any portion thereof)." That definition, then, is limited by a later statement which adds the term bulk power system "…does not include facilities used in the local distribution of electric energy." Also, Section 215 also covers users, owners, and operators of bulk power Facilities.

UFLS and UVLS (when the UVLS is installed to prevent system voltage collapse or voltage instability for BES reliability) are not "used in the local distribution of electric energy," despite their location on local distribution networks. Further, if UFLS/UVLS Facilities were not covered by the reliability standards, then in order to protect the integrity of the BES during under-frequency or under-voltage events, that Load would have to be shed at the Transmission bus to ensure the Load-generation balance and voltage stability is maintained on the BES.

15.8 Automatic Reclosing (Table 4)

Please see the document referenced in Section F of PRC-005-3, "Considerations for Maintenance and Testing of Autoreclosing Schemes — November 2012", for a discussion of Automatic Reclosing as addressed in PRC-005-3.

15.8.1 Frequently-asked Questions

Automatic Reclosing is a control, not a protective function; why then is Automatic Reclosing maintenance included in the Protection System Maintenance Program (PSMP)?

Automatic Reclosing is a control function. The standard's title 'Protection System and Automatic Reclosing Maintenance' clearly distinguishes (separates) the Automatic Reclosing from the Protection System. Automatic Reclosing is included in the PSMP because it is a more pragmatic approach as compared to creating a parallel and essentially identical 'Control System Maintenance Program' for the two Automatic Reclosing component types.

When do I need to have the initial maintenance of Automatic Reclosing Components completed upon change of the largest BES generating unit in the BA/RSG?

The maintenance interval, for newly identified Automatic Reclosing Components, starts when a change in the largest BES generating unit is determined by the BA/RSG. The first maintenance records for newly identified Automatic Reclosing Components should be dated no later than the maximum maintenance interval after the identification date. The maximum maintenance intervals for each newly identified Component are defined in Table 4. No activities or records are required prior to the date of identification.

Our maintenance practice consists of initiating the Automatic Reclosing relay and confirming the breaker closes properly and the close signal is released. This practice verifies the control circuitry associated with Automatic Reclosing. Do you agree?"

The described task partially verifies the control circuit maintenance activity. To meet the control circuit maintenance activity, responsible entities need to verify, *upon initiation*, that the reclosing relay does not issue a *premature closing command*. As noted on page 12 of the SAMS/SPCS report, the concern being addressed within the standard is premature auto reclosing that has the potential to cause generating unit or plant instability. Reclosing applications have many variations, responsible entities will need to verify the applicability of associated supervision/conditional logic and the reclosing relay operation; then verify the conditional logic or that the reclosing relay performs in a manner that does not result in a *premature closing command* being issued.

Some examples of conditions which can result in a premature closing command are: an improper supervision or conditional logic input which provides a false state and allows the reclosing relay to issue an improper close command based on incorrect conditions (i.e. voltage supervision, equipment status, sync window verification); timers utilized for closing actuation or reclosing arming/disarming circuitry which could allow the reclosing relay to issue an improper close command; a reclosing relay output contact failure which could result in a made-up-close condition / failure-to-release condition.

Why was a close-in three phase fault present for twice the normal clearing time chosen for the Automatic Reclosing exclusion? It exceeds TPL requirements and ignores the breaker closing time in a trip-close-trip sequence, thus making the exclusion harder to attain.

This condition represents a situation where a close signal is issued with no time delay or with less time delay than is intended, such as if a reclosing contact is welded closed. This failure mode can result in a minimum trip-close-trip sequence with the two faults cleared in primary protection operating time, and the open time between faults equal to the breaker closing cycle time. The sequence for this failure mode results in system impact equivalent to a high-speed autoreclosing sequence with no delay added in the autoreclosing logic. It represents a failure mode which must be avoided because it exceeds TPL requirements.

Do we have to test the various breaker closing circuit interlocks and controls such as anti-pump?

These components are not specifically addressed within Table 4, and need not be individually tested. They are indirectly verified by performing the Automatic Reclosing control circuitry verification as established in Table 4.

For Automatic Reclosing that <u>is not</u> part of an RAS, do we have to close the circuit breaker periodically?

No. For this application, you need only to verify that the Automatic Reclosing, upon initiation, does not issue a premature closing command. This activity is concerned only with assuring that a premature close does not occur, and cause generating plant instability.

For Automatic Reclosing that <u>is</u> part of an RAS, do we have to close the circuit breaker periodically?

Yes. In this application, successful closing is a necessary portion of the RAS, and must be verified.

15.9 Sudden Pressure Relaying (Table 5)

Please see the document referenced in Section F of PRC-005-4, "Sudden Pressure Relays and Other Devices that Respond to Non-Electrical Quantities – December 2013", for a discussion of Sudden Pressure Relaying as addressed in PRC-005-4.

15.9.1 Frequently Asked Questions:

How do I verify the pressure or flow sensing mechanism is operable?

Maintenance activities for the fault pressure relay associated with Sudden Pressure Relaying in PRC-005-4 are intended to verify that the pressure and/or flow sensing mechanism are functioning correctly. Beyond this, PRC-005-4 requires no calibration (adjusting the operating threshold or measurement accuracy of a measuring element to meet the intended performance requirement) or testing (applying signals to a component to observe functional performance or output behavior, or to diagnose problems) activities. For example, some designs of flow sensing mechanisms allow the operation of a test switch to actuate the limit switch of the flow sensing mechanism. Operation of this test switch and verification of the flow sensing mechanism would meet the requirements of the maintenance activity. Another example involves a gas pressure sensing mechanism which is isolated by a test plug. Removal of the plug and verification of the bellows mechanism would meet the requirements of the maintenance activity.

Why the 6-year maximum maintenance interval for fault pressure relays?

The SDT established the six-year maintenance interval for fault pressure relays (see Table 5, PRC-005-4) based on the recommendation of the System Protection and Control Subcommittee (SPCS). The technical experts of the SPCS were tasked with developing the technical documents to:

i. Describe the devices and functions (to include sudden pressure relays which trip for fault conditions) that should address FERC's concern; and

ii. Propose minimum maintenance activities for such devices and maximum maintenance intervals, including the technical basis for each.

Excerpt from the SPCS technical report: "In order to determine present industry practices related to sudden pressure relay maintenance, the SPCS conducted a survey of Transmission Owners and Generator Owners in all eight Regions requesting information related to their maintenance practices. The SPCS received responses from 75 Transmission Owners and 109 Generator Owners. Note that, for the purpose of the survey, sudden pressure relays included the following: the "sudden pressure relay" (SPR) originally manufactured by Westinghouse, the "rapid pressure rise relay" (RPR) manufactured by Qualitrol, and a variety of Buchholz relays.

Table 2 provides a summary of the results of the responses:

Table 2: Sudden Pressure Relay Maintenance Practices – Survey Results		
	Transmission Owner	**Generator Owner**
Number of responding owners that trip with Sudden Pressure Relays:	67	84

Percentage of responding owners who trip that have a Maintenance Program:	75%	78%
Percentage of maintenance programs that include testing the pressure actuator:	81%	77%
Average Maintenance interval reported:	5.9 years	4.9 years

Additionally, in order to validate the information noted above, the SPCS contacted the following entities for their feedback: the IEEE Power System Relaying Committee, the IEEE Transformer Committee, the Doble Transformer Committee, the NATF System Protection Practices Group, and the EPRI Generator Owner/Operator Technical Focus Group. All of these organizations indicated the results of the SPCS survey are consistent with their respective experiences.

The SPCS discussed the potential difference between the recommended intervals for fault pressure relaying and intervals for transformer maintenance. The SPCS developed the recommended intervals for fault pressure relaying by comparing fault pressure relaying to Protection System Components with similar physical attributes. The SPCS recognized that these intervals may be shorter than some existing or future transformer maintenance intervals, but believed it to be more important to base intervals for fault pressure relaying on similar Protection System Components than transformer maintenance intervals.

The maintenance interval for fault pressure relays can be extended by utilizing performance-based maintenance thereby allowing entities that have maintenance intervals for transformers in excess of six years, to align them.

Sudden Pressure Relaying control circuitry is now specifically mentioned in the maintenance tables. Do we have to trip our circuit breaker specifically from the trip output of the sudden pressure relay?

No. Verification may be by breaker tripping, but may be verified in overlapping segments with the Protection System control circuitry.

Can we use Performance Based Maintenance for fault pressure relays?

Yes. Performance Based Maintenance is applicable to fault pressure relays.

15.10 Examples of Evidence of Compliance

To comply with the requirements of this standard, an entity will have to document and save evidence. The evidence can be of many different forms. The Standard Drafting Team recognizes that there are concurrent evidence requirements of other NERC standards that could, at times, fulfill evidence requirements of this standard.

15.10.1 Frequently Asked Questions:

What forms of evidence are acceptable?

Acceptable forms of evidence, as relevant for the requirement being documented include, but are not limited to:

- Process documents or plans

- Data (such as relay settings sheets, photos, SCADA, and test records)
- Database lists, records and/or screen shots that demonstrate compliance information
- Prints, diagrams and/or schematics
- Maintenance records
- Logs (operator, substation, and other types of log)
- Inspection forms
- Mail, memos, or email proving the required information was exchanged, coordinated, submitted or received
- Check-off forms (paper or electronic)
- Any record that demonstrates that the maintenance activity was known, accounted for, and/or performed.

If I replace a failed Protection System component with another component, what testing do I need to perform on the new component?

In order to reset the Table 1 maintenance interval for the replacement component, all relevant Table 1 activities for the component should be performed.

I have evidence to show compliance for PRC-016 ("Special Protection System Misoperation"). Can I also use it to show compliance for this Standard, PRC-005-4?

Maintaining evidence for operation of Remedial Action Systems could concurrently be utilized as proof of the operation of the associated trip coil (provided one can be certain of the trip coil involved). Thus, the reporting requirements that one may have to do for the Misoperation of a Special Protection Scheme under PRC-016 could work for the activity tracking requirements under this PRC-005-4.

I maintain Disturbance records which show Protection System operations. Can I use these records to show compliance?

These records can be concurrently utilized as dc trip path verifications, to the degree that they demonstrate the proper function of that dc trip path.

I maintain test reports on some of my Protection System components. Can I use these test reports to show that I have verified a maintenance activity?

Yes.

References

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3. "Transmission Relay System Performance Comparison For 2000, 2001, 2002, 2003, 2004 and 2005," Working Group I17 of Power System Relaying Committee of IEEE Power Engineering Society, May 2006.

4. "A Survey of Relaying Test Practices," Special Report by WG I11 of Power System Relaying Committee of IEEE Power Engineering Society, September 16, 1999.

5. “Transmission Protective Relay System Performance Measuring Methodology,” Working Group I3 of Power System Relaying Committee of IEEE Power Engineering Society, January 2002.

6. “Processes, Issues, Trends and Quality Control of Relay Settings,” Working Group C3 of Power System Relaying Committee of IEEE Power Engineering Society, December 2006.

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8. “Analysis And Guidelines For Testing Numerical Protection Schemes,” Final Report of CIGRE WG 34.10, August 2000.

9. “Use of Preventative Maintenance and System Performance Data to Optimize Scheduled Maintenance Intervals,” H. Anderson, R. Loughlin, and J. Zipp, Georgia Tech Protective Relay Conference, May 1996.

10. “Battery Performance Monitoring by Internal Ohmic Measurements” EPRI Application Guidelines for Stationary Batteries TR- 108826 Final Report, December 1997.

11. “IEEE Recommended Practice for Maintenance, Testing, and Replacement of Valve-Regulated Lead-Acid (VRLA) Batteries for Stationary Applications,” IEEE Power Engineering Society Std 1188 – 2005.

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15. “Stationary Battery Guide: Design Application, and Maintenance” EPRI Revision 2 of TR-100248, 1006757, August 2002.

PSMT SDT References

16. “Essentials of Statistics for Business and Economics” Anderson, Sweeney, Williams, 2003

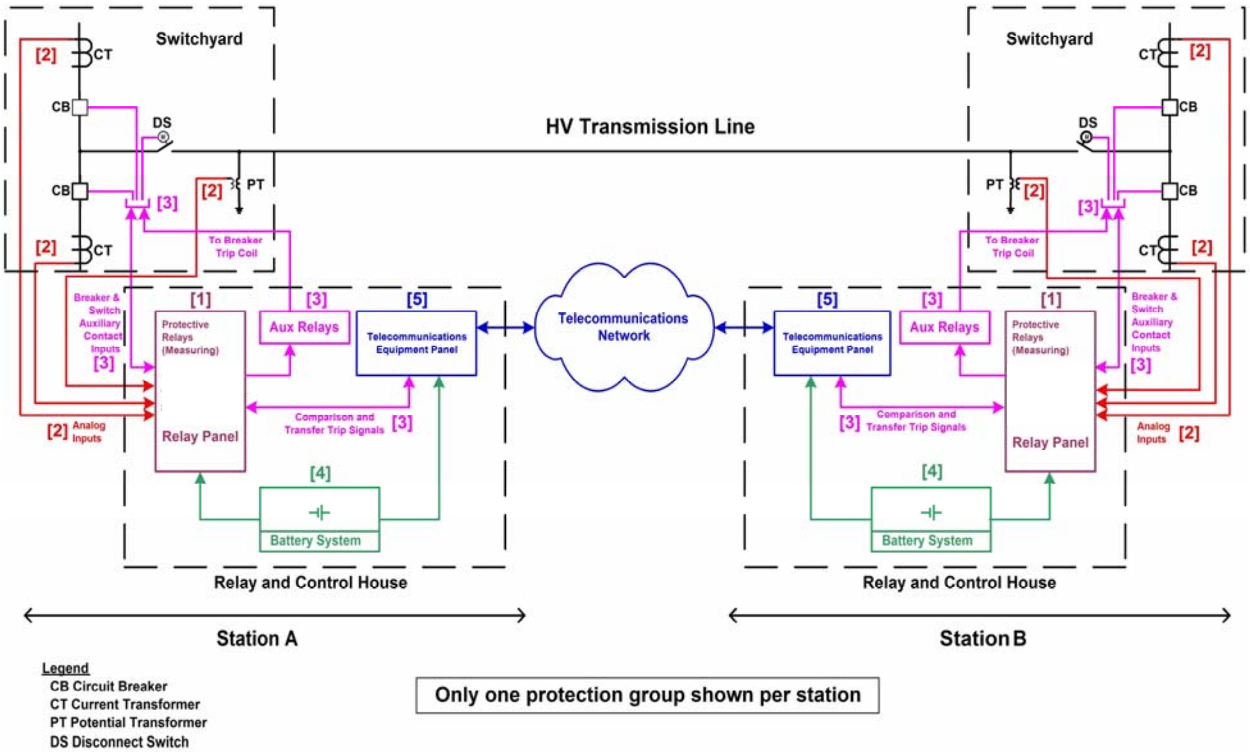
17. “Introduction to Statistics and Data Analysis” - Second Edition, Peck, Olson, Devore, 2005

18. “Statistical Analysis for Business Decisions” Peters, Summers, 1968

19. “Considerations for Maintenance and Testing of Autoreclosing Schemes,” NERC System Analysis and Modeling Subcommittee and NERC System Protection and Control Subcommittee, November 2012

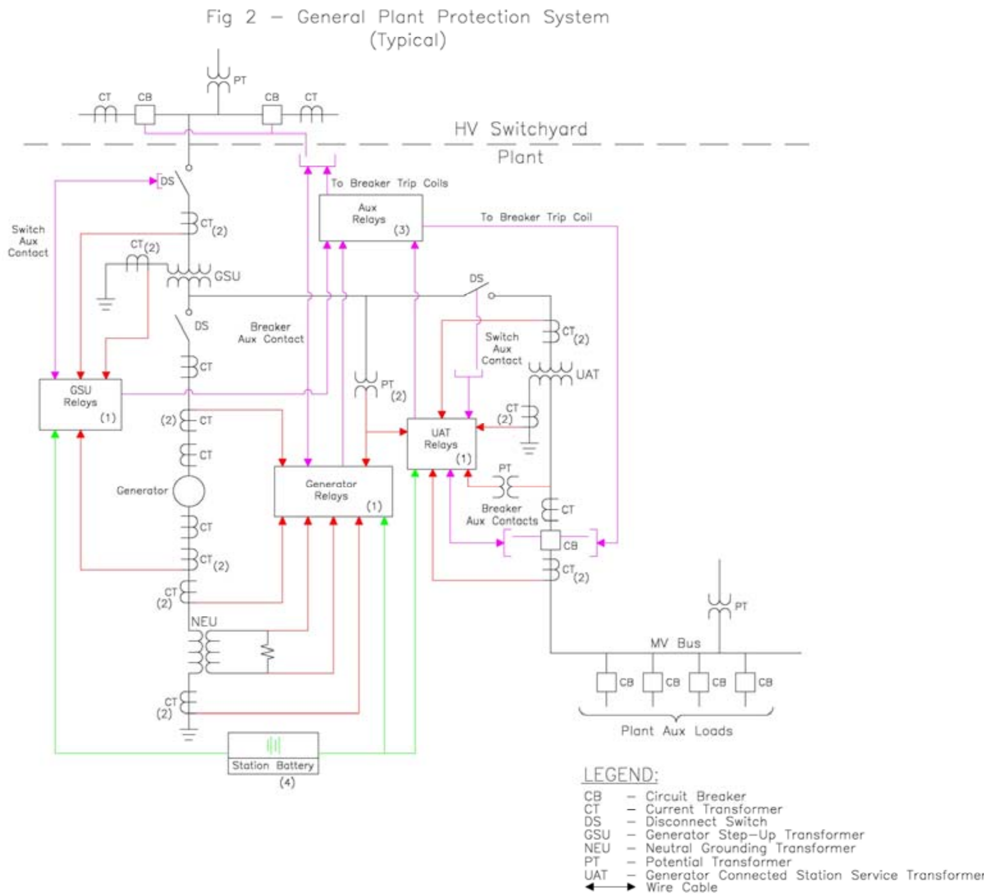
Figures

Figure 1: Typical Transmission System



For information on components, see ***[Figure 1 & 2 Legend – components of Protection Systems]()***

Figure 2: Typical Generation System



Note: Figure 2 may show elements that are not included within PRC-005-2, and also may not be all-inclusive; see the Applicability section of the standard for specifics.

For information on components, see ***Figure 1 & 2 Legend – components of Protection Systems***

Figure 1 & 2 Legend – Components of Protection Systems

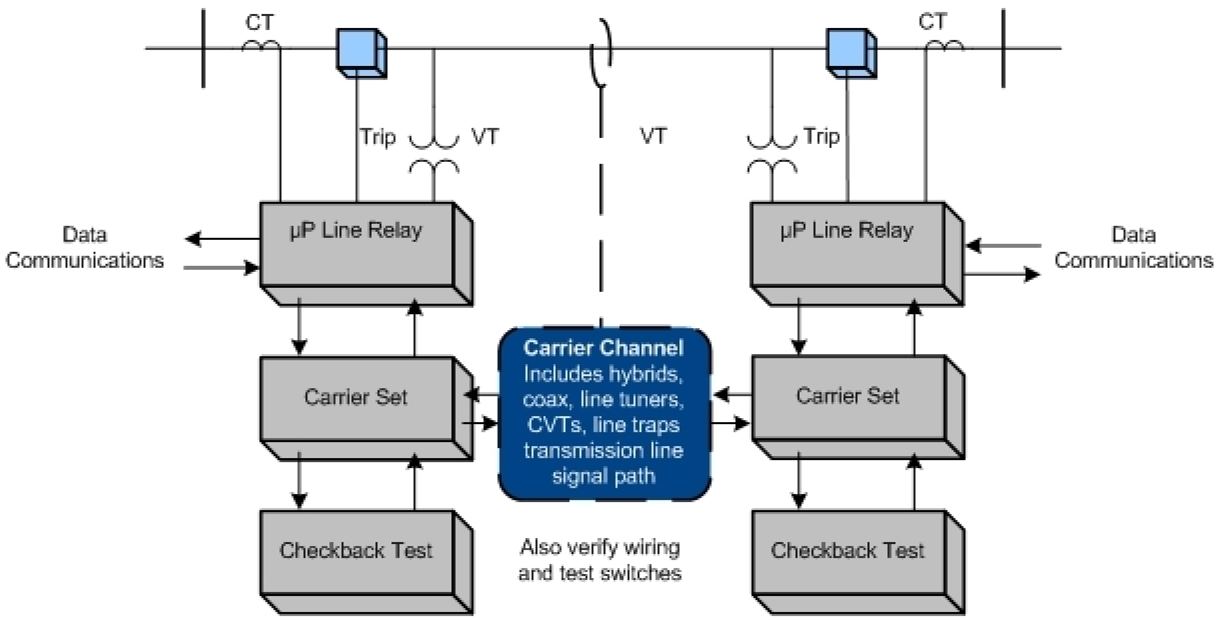
Number in Figure	Component of Protection System	Includes	Excludes
1	Protective relays which respond to electrical quantities	All protective relays that use current and/or voltage inputs from current & voltage sensors and that trip the 86, 94 or trip coil.	Devices that use non-electrical methods of operation including thermal, pressure, gas accumulation, and vibration. Any ancillary equipment not specified in the definition of Protection Systems. Control and/or monitoring equipment that is not a part of the automatic tripping action of the Protection System
2	Voltage and current sensing devices providing inputs to protective relays	The signals from the voltage & current sensing devices to the protective relay input.	Voltage & current sensing devices that are not a part of the Protection System, including sync-check systems, metering systems and data acquisition systems.
3	Control circuitry associated with protective functions	All control wiring (or other medium for conveying trip signals) associated with the tripping action of 86 devices, 94 devices or trip coils (from all parallel trip paths). This would include fiber-optic systems that carry a trip signal as well as hard-wired systems that carry trip current.	Closing circuits, SCADA circuits, other devices in control scheme not passing trip current
4	Station dc supply	Batteries and battery chargers and any control power system which has the function of supplying power to the protective relays, associated trip circuits and trip coils.	Any power supplies that are not used to power protective relays or their associated trip circuits and trip coils.
5	Communications systems necessary for correct operation of protective functions	Tele-protection equipment used to convey specific information, in the form of analog or digital signals, necessary for the correct operation of protective functions.	Any communications equipment that is not used to convey information necessary for the correct operation of protective functions.

Additional information can be found in References

Appendix A

The following illustrates the concept of overlapping verifications and tests as summarized in Section 10 of the paper. As an example, Figure A-1 shows protection for a critical transmission line by carrier blocking directional comparison pilot relaying. The goal is to verify the ability of the entire two-terminal pilot protection scheme to protect for line Faults, and to avoid over-tripping for Faults external to the transmission line zone of protection bounded by the current transformer locations.

Figure A-1



In this example (Figure A1), verification takes advantage of the self-monitoring features of microprocessor multifunction line relays at each end of the line. For each of the line relays themselves, the example assumes that the user has the following arrangements in place:

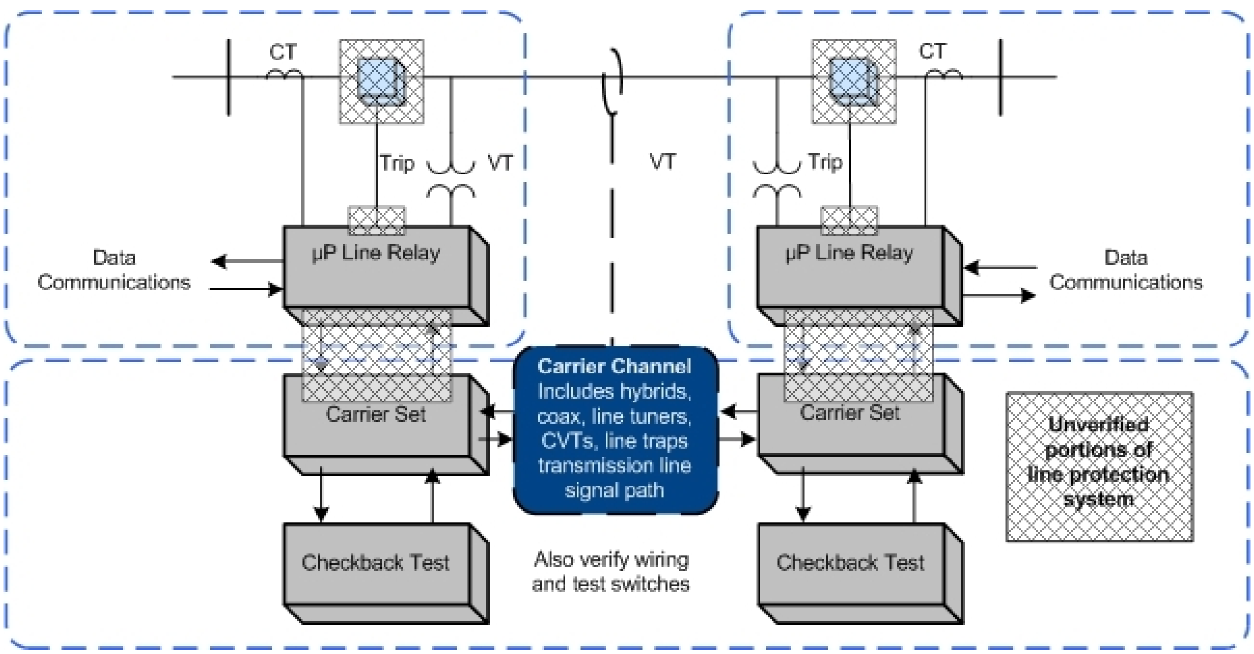
1. The relay has a data communications port that can be accessed from remote locations.
2. The relay has internal self-monitoring programs and functions that report failures of internal electronics, via communications messages or alarm contacts to SCADA.
3. The relays report loss of dc power, and the relays themselves or external monitors report the state of the dc battery supply.
4. The CT and PT inputs to the relays are used for continuous calculation of metered values of volts, amperes, plus Watts and VARs on the line. These metered values are reported by data communications. For maintenance, the user elects to compare these readings to those of other relays, meters, or DFRs. The other readings may be from redundant relaying or measurement systems or they may be derived from values in other protection zones. Comparison with other such readings to within required relaying accuracy verifies voltage & current sensing devices, wiring, and analog signal input processing of the relays. One

effective way to do this is to utilize the relay metered values directly in SCADA, where they can be compared with other references or state estimator values.

5. Breaker status indication from auxiliary contacts is verified in the same way as in (2). Status indications must be consistent with the flow or absence of current.
6. Continuity of the breaker trip circuit from dc bus through the trip coil is monitored by the relay and reported via communications.
7. Correct operation of the on-off carrier channel is also critical to security of the Protection System, so each carrier set has a connected or integrated automatic checkback test unit. The automatic checkback test runs several times a day. Newer carrier sets with integrated checkback testing check for received signal level and report abnormal channel attenuation or noise, even if the problem is not severe enough to completely disable the channel.

These monitoring activities plus the check-back test comprise automatic verification of all the Protection System elements that experience tells us are the most prone to fail. But, does this comprise a complete verification?

Figure A-2



The dotted boxes of Figure A-2 show the sections of verification defined by the monitoring and verification practices just listed. These sections are not completely overlapping, and the shaded regions show elements that are not verified:

1. The continuity of trip coils is verified, but no means is provided for validating the ability of the circuit breaker to trip if the trip coil should be energized.

2. Within each line relay, all the microprocessors that participate in the trip decision have been verified by internal monitoring. However, the trip circuit is actually energized by the contacts of a small telephone-type "ice cube" relay within the line protective relay. The microprocessor energizes the coil of this ice cube relay through its output data port and a transistor driver circuit. There is no monitoring of the output port, driver circuit, ice cube relay, or contacts of that relay. These components are critical for tripping the circuit breaker for a Fault.
3. The check-back test of the carrier channel does not verify the connections between the relaying microprocessor internal decision programs and the carrier transmitter keying circuit or the carrier receiver output state. These connections include microprocessor I/O ports, electronic driver circuits, wiring, and sometimes telephone-type auxiliary relays.
4. The correct states of breaker and disconnect switch auxiliary contacts are monitored, but this does not confirm that the state change indication is correct when the breaker or switch opens.

A practical solution for (1) and (2) is to observe actual breaker tripping, with a specified maximum time interval between trip tests. Clearing of naturally-occurring Faults are demonstrations of operation that reset the time interval clock for testing of each breaker tripped in this way. If Faults do not occur, manual tripping of the breaker through the relay trip output via data communications to the relay microprocessor meets the requirement for periodic testing.

PRC-005-4 does not address breaker maintenance, and its Protection System test requirements can be met by energizing the trip circuit in a test mode (breaker disconnected) through the relay microprocessor. This can be done via a front-panel button command to the relay logic, or application of a simulated Fault with a relay test set. However, utilities have found that breakers often show problems during Protection System tests. It is recommended that Protection System verification include periodic testing of the actual tripping of connected circuit breakers.

Testing of the relay-carrier set interface in (3) requires that each relay key its transmitter, and that the other relay demonstrate reception of that blocking carrier. This can be observed from relay or DFR records during naturally occurring Faults, or by a manual test. If the checkback test sequence were incorporated in the relay logic, the carrier sets and carrier channel are then included in the overlapping segments monitored by the two relays, and the monitoring gap is completely eliminated.

Appendix B

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Exhibit G

Analysis of Violation Risk Factors and Violation Severity Levels

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Violation Risk Factor and Violation Severity Level Justifications

Project 2007-17.3 PRC-005-4
Protection System, Automatic Reclosing, and Sudden Pressure Relaying Maintenance

Violation Risk Factor and Violation Severity Level Justifications

This document provides the drafting team's justification for assignment of violation risk factors (VRFs) and violation severity levels (VSLs) for each requirement in PRC-005-4 - Protection System, Automatic Reclosing, and Sudden Pressure Relaying Maintenance.

Each primary requirement is assigned a VRF and a set of one or more VSLs. These elements support the determination of an initial value range for the Base Penalty Amount regarding violations of requirements in FERC-approved Reliability Standards, as defined in the ERO Sanction Guidelines.

The Protection System Maintenance and Testing Standard Drafting Team applied the following NERC criteria and FERC Guidelines when proposing VRFs and VSLs for the requirements under this project:

NERC Criteria – VRFs

High Risk Requirement

A requirement that, if violated, could directly cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures, or could place the bulk electric system at an unacceptable risk of instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures, or could place the bulk electric system at an unacceptable risk of instability, separation, or cascading failures, or could hinder restoration to a normal condition.

Medium Risk Requirement

A requirement that, if violated, could directly affect the electrical state or the capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system. However, violation of a medium risk requirement is unlikely to lead to bulk electric system instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system. However, violation of a medium risk requirement is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to bulk electric system instability, separation, or cascading failures, nor to hinder restoration to a normal condition.

Lower Risk Requirement

A requirement that is administrative in nature and a requirement that, if violated, would not be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system; or, a requirement that is administrative in nature and a requirement in a planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system. A planning requirement that is administrative in nature.

FERC VRF Guidelines

Guideline (1) — Consistency with the Conclusions of the Final Blackout Report

The Commission seeks to ensure that VRFs assigned to Requirements of Reliability Standards in these identified areas appropriately reflect their historical critical impact on the reliability of the Bulk-Power System.

In the VSL Order, FERC listed critical areas (from the Final Blackout Report) where violations could severely affect the reliability of the Bulk-Power System:

Emergency operations

Vegetation management

Operator personnel training

Protection systems and their coordination

Operating tools and backup facilities

Reactive power and voltage control

System modeling and data exchange

Communication protocol and facilities

Requirements to determine equipment ratings

Synchronized data recorders

Clearer criteria for operationally critical facilities

Appropriate use of transmission loading relief

Guideline (2) — Consistency within a Reliability Standard

The Commission expects a rational connection between the sub-Requirement VRF assignments and the main Requirement VRF assignment.

Guideline (3) — Consistency among Reliability Standards

The Commission expects the assignment of VRFs corresponding to Requirements that address similar reliability goals in different Reliability Standards would be treated comparably.

Guideline (4) — Consistency with NERC's Definition of the VRF Level

Guideline (4) was developed to evaluate whether the assignment of a particular VRF level conforms to NERC's definition of that risk level.

Guideline (5) — Treatment of Requirements that Co-mingle More Than One Obligation

Where a single Requirement co-mingles a higher risk reliability objective and a lesser risk reliability objective, the VRF assignment for such Requirements must not be watered down to reflect the lower risk level associated with the less important objective of the Reliability Standard.

The following discussion addresses how the SDT considered FERC's VRF Guidelines 2 through 5. The team did not address Guideline 1 directly because of an apparent conflict between Guidelines 1 and 4. Whereas Guideline 1 identifies a list of topics that encompass nearly all topics within NERC's Reliability Standards and implies that these requirements should be assigned a "High" VRF, Guideline 4 directs assignment of VRFs based on the impact of a specific requirement to the reliability of the system. The SDT believes that Guideline 4 is reflective of the intent of VRFs in the first instance and therefore concentrated its approach on the reliability impact of the requirements.

PRC-005-4 Protection System, Automatic Reclosing and Sudden Pressure Relaying Maintenance is a revision of PRC-005-3 Protection System and Automatic Reclosing Maintenance with the stated purpose: To document and implement programs for the maintenance of all Protection Systems, Automatic Reclosing, and Sudden Pressure Relaying affecting the reliability of the Bulk Electric System (BES) so that they are kept in working order.

PRC-005-4 has five (5) requirements that address the inclusion of Sudden Pressure Relaying. A Table of minimum maintenance activities and maximum maintenance intervals for Sudden Pressure Relaying has been added to PRC-005-3 to address FERC's directives from Order 758. The revised standard requires that entities develop an appropriate Protection System Maintenance Program (PSMP), that they implement their PSMP, and that, in the event they are unable to restore Sudden Pressure Relaying Components to proper working order while performing maintenance, they initiate the follow-up activities necessary to resolve those maintenance issues.

The requirements of PRC-005-4 map one-to-one with the requirements of PRC-005-3. The drafting team did not revise the VRFs for the requirements of PRC-005-3.

PRC-005-4 Requirements R1 and R2 are related to developing and documenting a Protection System Maintenance Program. The Standard Drafting Team determined that the assignment of a VRF of Medium was consistent with the NERC criteria that violations of these requirements could directly affect the electrical state or the capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system but are unlikely to lead to bulk electric system instability, separation, or cascading failures. Additionally, a review of the body of existing NERC Standards with approved VRFs revealed that requirements with similar reliability objectives in other standards are largely assigned a VRF of Medium.

PRC-005-4 Requirements R3 and R4 are related to implementation of the Protection System Maintenance Program. The SDT determined that the assignment of a VRF of High was consistent with the NERC criteria that that violation of these requirements could directly cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures, or could place the bulk electric system at an unacceptable risk of instability, separation, or cascading failures. Additionally, a review of the body of existing NERC Standards with approved VRFs revealed that requirements with similar reliability objectives in other standards are assigned a VRF of High.

PRC-005-4 Requirement R5 relates to the initiation of resolution of unresolved maintenance issues, which describe situations where an entity was unable to restore a Component to proper working order during the performance of the maintenance activity. The Standard Drafting Team determined that the assignment of a VRF of Medium was consistent with the NERC criteria that violation of this requirements could directly affect the electrical state or the capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system but are unlikely to lead to bulk electric system instability, separation, or cascading failures. Additionally, a review of the body of existing NERC Standards with approved VRFs revealed that requirements with similar reliability objectives in other standards are largely assigned a VRF of Medium.

NERC Criteria - VSLs

VSLs define the degree to which compliance with a requirement was not achieved. Each requirement must have at least one VSL. While it is preferable to have four VSLs for each requirement, some requirements do not have multiple “degrees” of noncompliant performance and may have only one, two, or three VSLs.

VSLs should be based on the guidelines shown in the table below:

Lower	Moderate	High	Severe
Missing a minor element (or a small percentage) of the required performance The performance or product measured has significant value as it almost meets the full intent of the requirement.	Missing at least one significant element (or a moderate percentage) of the required performance. The performance or product measured still has significant value in meeting the intent of the requirement.	Missing more than one significant element (or is missing a high percentage) of the required performance or is missing a single vital Component. The performance or product has limited value in meeting the intent of the requirement.	Missing most or all of the significant elements (or a significant percentage) of the required performance. The performance measured does not meet the intent of the requirement or the product delivered cannot be used in meeting the intent of the requirement.

FERC Order on VSLs

In its June 19, 2008 Order on VSLs, FERC indicated it would use the following four guidelines for determining whether to approve VSLs:

Guideline 1: VSL Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance

- Compare the VSLs to any prior Levels of Non-compliance and avoid significant changes that may encourage a lower level of compliance than was required when Levels of Non-compliance were used.

Guideline 2: VSL Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties

- Guideline 2a: A violation of a "binary" type requirement must be a "Severe" VSL.
- Guideline 2b: Do not use ambiguous terms such as "minor" and "significant" to describe noncompliant performance.

Guideline 3: VSL Assignment Should Be Consistent with the Corresponding Requirement

- VSLs should not expand on what is required in the requirement.

Guideline 4: VSL Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations

- . . . unless otherwise stated in the requirement, each instance of non-compliance with a requirement is a separate violation. Section 4 of the Sanction Guidelines states that assessing penalties on a per violation per day basis is the "default" for penalty calculations.

VRF and VSL Justifications

VRF and VSL Justifications – PRC-005-4, R1	
Proposed VRF	**Medium**
NERC VRF Discussion	Failure to establish a Protection System Maintenance Program (PSMP) for Protection Systems designed to provide protection for BES Element(s) could directly affect the electrical state or the capability of the bulk power system. However, violation of this requirement is unlikely to lead to bulk power system instability, separation, or cascading failures. The applicable entities are always responsible for maintaining the reliability of the bulk power system regardless of the situation. This VRF emphasizes the risk to system performance that results from mal-performing Protection System Components. Failure to establish a Protection System Maintenance Program (PSMP) for Protection Systems will not, by itself, lead to instability, separation, or cascading failures. Thus, the requirement meets NERC's criteria for a Medium VRF.
FERC VRF G1 Discussion	Guideline 1- Consistency w/ Blackout Report: N/A
FERC VRF G2 Discussion	Guideline 2- Consistency within a Reliability Standard: The requirement has no sub-requirements so only one VRF was assigned. The requirement utilizes Parts to identify the items to be included within a Protection System Maintenance Program. The VRF for this requirement is consistent with others in the standard with regard to relative risk; therefore, there is no conflict.
FERC VRF G3 Discussion	Guideline 3- Consistency among Reliability Standards: The SDT has determined that there is no consistency among existing approved Standards relative to requirements of this nature. The SDT has assigned a MEDIUM VRF, which is consistent with recent FERC guidance on FAC-008-3 Requirement R2 and FAC-013-2 Requirement R1, which are similar in nature to PRC-005-4 Requirement R1.

VRF and VSL Justifications – PRC-005-4, R1			
Proposed VRF	**Medium**		
FERC VRF G4 Discussion	Guideline 4- Consistency with NERC Definitions of VRFs: Failure to establish a Protection System Maintenance Program (PSMP) for Protection Systems designed to provide protection for BES Element(s) could directly affect the electrical state or the capability of the bulk power system. However, violation of this requirement is unlikely to lead to bulk power system instability, separation, or cascading failures. The applicable entities are always responsible for maintaining the reliability of the bulk power system regardless of the situation. This VRF emphasizes the risk to system performance that results from mal-performing Protection System Components. Failure to establish a Protection System Maintenance Program (PSMP) for Protection Systems will not, by itself, lead to instability, separation, or cascading failures. Thus, the requirement meets NERC's criteria for a Medium VRF.		
FERC VRF G5 Discussion	Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation: This requirement establishes a single risk-level, and the assigned VRF is consistent with that risk level.		
Proposed VSL – PRC-005-4, R1			
Lower	**Moderate**	**High**	**Severe**
The entity's PSMP failed to specify whether one Component Type is being addressed by time-based or performance-based maintenance, or a combination of both. (Part 1.1)	The entity's PSMP failed to specify whether two Component Types are being addressed by time-based or performance-based maintenance, or a combination of both. (Part 1.1)	The entity's PSMP failed to specify whether three Component Types are being addressed by time-based or performance-based maintenance, or a combination of both. (Part 1.1). OR	The entity failed to establish a PSMP. OR The entity's PSMP failed to specify whether four or more Component Types are being addressed by time-based or performance-based maintenance, or a combination of both. (Part 1.1).

Proposed VSL – PRC-005-4, R1			
Lower	**Moderate**	**High**	**Severe**
		The entity's PSMP failed to include the applicable monitoring attributes applied to each Component Type consistent with the maintenance intervals specified in Tables 1-1 through 1-5, Table 2, Table 3, Table 4-1 through 4-2, and Table 5where monitoring is used to extend the maintenance intervals beyond those specified for unmonitored Components. (Part 1.2).	OR The entity's PSMP failed to include applicable station batteries in a time-based program (Part 1.1)

VRF and VSL Justifications – PRC-005-4, R1	
NERC VSL Guidelines	Meets NERC's VSL Guidelines—There is an incremental aspect to the violation and the VSLs follow the guidelines for incremental violations.
FERC VSL G1 VSL Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	This VSL is consistent with the current VSLs associated with the existing requirements of the standards being replaced by this proposed standard.
FERC VSL G2 VSL Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single VSL Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: VSL Assignments that Contain Ambiguous Language	Guideline 2a: N/A Guideline 2b: The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.

VRF and VSL Justifications – PRC-005-4, R1	
FERC VSL G3 VSL Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses similar terminology to that used in the associated requirement, and is therefore consistent with the requirement.
FERC VSL G4 VSL Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The VSL is based on a single violation and not cumulative violations.

VRF and VSL Justifications – PRC-005-4, R2	
Proposed VRF	**Medium**
NERC VRF Discussion	Failure to properly establish a performance-based Protection System Maintenance Program (PSMP) for Protection Systems designed to provide protection for BES Element(s) could directly affect the electrical state or the capability of the bulk power system. However, violation of this requirement is unlikely to lead to bulk power system instability, separation, or cascading failures. The applicable entities are always responsible for maintaining the reliability of the bulk power system regardless of the situation. This VRF emphasizes the risk to system performance that results from mal-performing Protection System Components. Failure to properly establish a performance-based Protection System Maintenance Program (PSMP) for Protection Systems will not, by itself, lead to instability, separation, or cascading failures. Thus, the requirement meets NERC's criteria for a Medium VRF.
FERC VRF G1 Discussion	Guideline 1- Consistency w/ Blackout Report: N/A
FERC VRF G2 Discussion	Guideline 2- Consistency within a Reliability Standard: The requirement has no subpart(s); therefore, only one VRF was assigned and no conflict(s) exist.
FERC VRF G3 Discussion	Guideline 3- Consistency among Reliability Standards: The SDT has determined that there is no consistency among existing approved Standards relative to requirements of this nature. The SDT has assigned a MEDIUM VRF, which is consistent with recent FERC guidance on FAC-008-3 Requirement R2 and FAC-013-2 Requirement R1, which are similar in nature to PRC-005-4 Requirement R1.
FERC VRF G4 Discussion	Guideline 4- Consistency with NERC Definitions of VRFs: Failure to properly establish a performance-based Protection System Maintenance Program (PSMP) for.

VRF and VSL Justifications – PRC-005-4, R2			
Proposed VRF	**Medium**		
	Protection Systems designed to provide protection for BES Element(s) could directly affect the electrical state or the capability of the bulk power system. However, violation of this requirement is unlikely to lead to bulk power system instability, separation, or cascading failures. The applicable entities are always responsible for maintaining the reliability of the bulk power system regardless of the situation. This VRF emphasizes the risk to system performance that results from mal-performing Protection System Components. Failure to properly establish a performance-based Protection System Maintenance Program (PSMP) for Protection Systems will not, by itself, lead to instability, separation, or cascading failures. Thus, the requirement meets NERC's criteria for a Medium VRF.		
FERC VRF G5 Discussion	Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation: This requirement establishes a single risk-level, and the assigned VRF is consistent with that risk level.		
Proposed VSL – PRC-005-4, R2			
Lower	**Moderate**	**High**	**Severe**
The entity uses performance-based maintenance intervals in its PSMP but failed to reduce Countable Events to no more than 4% within three years.	N/A	The entity uses performance-based maintenance intervals in its PSMP but failed to reduce Countable Events to no more than 4% within four years.	The entity uses performance-based maintenance intervals in its PSMP but: 1) Failed to establish the technical justification described within Requirement R2 for the initial use of the performance-based PSMP

Proposed VSL – PRC-005-4, R2			
Lower	**Moderate**	**High**	**Severe**
			OR 2) Failed to reduce countable events to no more than 4% within five years OR 3) Maintained a Segment with less than 60 Components OR 4) Failed to: • Annually update the list of Components, OR • Annually perform maintenance on the greater of 5% of the Segment population or 3 Components, OR • Annually analyze the program activities and results for each Segment.

VRF and VSL Justifications – PRC-005-4, R2	
NERC VSL Guidelines	Meets NERC's VSL Guidelines—There is an incremental aspect to the violation and the VSLs follow the guidelines for incremental violations.
FERC VSL G1 VSL Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	This VSL is consistent with the current VSLs associated with the existing requirements of the standards being replaced by this proposed standard.
FERC VSL G2 VSL Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single VSL Assignment Category for "Binary" Requirements Is Not Consistent	Guideline 2a: N/A Guideline 2b: The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.

VRF and VSL Justifications – PRC-005-4, R2	
Guideline 2b: VSL Assignments that Contain Ambiguous Language	
FERC VSL G3 VSL Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses similar terminology to that used in the associated requirement, and is therefore consistent with the requirement.
FERC VSL G4 VSL Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The VSL is based on a single violation and not cumulative violations.

VRF and VSL Justifications – PRC-005-4, R3	
Proposed VRF	**High**
NERC VRF Discussion	Failure to implement and follow its Protection System Maintenance Program (PSMP) could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures, or could place the bulk electric system at an unacceptable risk of instability, separation, or cascading failures, or could hinder restoration to a normal condition. Thus, this requirement meets the criteria for a High VRF.
FERC VRF G1 Discussion	Guideline 1- Consistency w/ Blackout Report: N/A
FERC VRF G2 Discussion	Guideline 2- Consistency within a Reliability Standard: The requirement has no subpart(s); therefore, only one VRF was assigned and no conflict(s) exist.
FERC VRF G3 Discussion	Guideline 3- Consistency among Reliability Standards: The only Reliability Standards with similar goals are those being replaced by this standard, and the High VRF assignment for this requirement is consistent with the assigned VRFs for companion requirements in those existing standards.
FERC VRF G4 Discussion	Guideline 4- Consistency with NERC Definitions of VRFs: Failure to implement and follow its Protection System Maintenance Program (PSMP) could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures, or could place the bulk electric system at an unacceptable risk of instability, separation, or cascading failures, or could hinder restoration to a normal condition. Thus, this requirement meets the criteria for a High VRF.
FERC VRF G5 Discussion	Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation: This requirement establishes a single risk-level, and the assigned VRF is consistent with that risk level.

Proposed VSL – PRC-005-4, R3			
Lower	**Moderate**	**High**	**Severe**
For Components included within a time-based maintenance program, the entity failed to maintain 5% or less of the total Components included within a specific Component Type, in accordance with the minimum maintenance activities and maximum maintenance intervals prescribed within Tables 1-1 through 1-5, Table 2, Table 3, Table 4-1 through 4-2, and Table 5.	For Components included within a time-based maintenance program, the entity failed to maintain more than 5% but 10% or less of the total Components included within a specific Component Type, in accordance with the minimum maintenance activities and maximum maintenance intervals prescribed within Tables 1-1 through 1-5, Table 2, Table 3, Table 4-1 through 4-2, and Table 5.	For Components included within a time-based maintenance program, the entity failed to maintain more than 10% but 15% or less of the total Components included within a specific Component Type, in accordance with the minimum maintenance activities and maximum maintenance intervals prescribed within Tables 1-1 through 1-5, Table 2, Table 3, Table 4-1 through 4-2, and Table 5.	For Components included within a time-based maintenance program, the entity failed to maintain more than 15% of the total Components included within a specific Component Type, in accordance with the minimum maintenance activities and maximum maintenance intervals prescribed within Tables 1-1 through 1-5, Table 2, Table 3, Table 4-1 through 4-2, and Table 5.

VRF and VSL Justifications – PRC-005-4, R3	
NERC VSL Guidelines	Meets NERC's VSL Guidelines—There is an incremental aspect to the violation and the VSLs follow the guidelines for incremental violations.
FERC VSL G1 VSL Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	This VSL is consistent with the current VSLs associated with the existing requirements of the standards being replaced by this proposed standard.
FERC VSL G2 VSL Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single VSL Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: VSL Assignments that Contain Ambiguous Language	Guideline 2a: N/A Guideline 2b: The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.

VRF and VSL Justifications – PRC-005-4, R3	
FERC VSL G3 VSL Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses similar terminology to that used in the associated requirement, and is therefore consistent with the requirement.
FERC VSL G4 VSL Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The VSL is based on a single violation and not cumulative violations.

VRF and VSL Justifications – PRC-005-4, R4	
Proposed VRF	**High**
NERC VRF Discussion	Failure to implement and follow its Protection System Maintenance Program (PSMP) could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures, or could place the bulk electric system at an unacceptable risk of instability, separation, or cascading failures, or could hinder restoration to a normal condition. Thus, this requirement meets the criteria for a High VRF.
FERC VRF G1 Discussion	Guideline 1- Consistency w/ Blackout Report: N/A
FERC VRF G2 Discussion	Guideline 2- Consistency within a Reliability Standard: The requirement has no subpart(s); therefore, only one VRF was assigned and no conflict(s) exist.
FERC VRF G3 Discussion	Guideline 3- Consistency among Reliability Standards: The only Reliability Standards with similar goals are those being replaced by this standard, and the High VRF assignment for this requirement is consistent with the assigned VRFs for companion requirements in those existing standards.
FERC VRF G4 Discussion	Guideline 4- Consistency with NERC Definitions of VRFs: Failure to implement and follow its Protection System Maintenance Program (PSMP) could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures, or could place the bulk electric system at an unacceptable risk of instability, separation, or cascading failures, or could hinder restoration to a normal condition. Thus, this requirement meets the criteria for a High VRF.
FERC VRF G5 Discussion	Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation: This requirement establishes a single risk-level, and the assigned VRF is consistent with that risk level.

Proposed VSL – PRC-005-4, R4			
Lower	**Moderate**	**High**	**Severe**
For Components included within a performance-based maintenance program, the entity failed to maintain 5% or less of the annual scheduled maintenance for a specific Component Type in accordance with their performance-based PSMP.	For Components included within a performance-based maintenance program, the entity failed to maintain more than 5% but 10% or less of the annual scheduled maintenance for a specific Component Type in accordance with their performance-based PSMP.	For Components included within a performance-based maintenance program, the entity failed to maintain more than 10% but 15% or less of the annual scheduled maintenance for a specific Component Type in accordance with their performance-based PSMP.	For Components included within a performance-based maintenance program, the entity failed to maintain more than 15% of the annual scheduled maintenance for a specific Component Type in accordance with their performance-based PSMP.

VRF and VSL Justifications – PRC-005-4, R4	
NERC VSL Guidelines	Meets NERC's VSL Guidelines—There is an incremental aspect to the violation and the VSLs follow the guidelines for incremental violations.
FERC VSL G1 VSL Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	This VSL is consistent with the current VSLs associated with the existing requirements of the standards being replaced by this proposed standard.
FERC VSL G2 VSL Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single VSL Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: VSL Assignments that Contain Ambiguous Language	Guideline 2a: N/A Guideline 2b: The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.

VRF and VSL Justifications – PRC-005-4, R4	
FERC VSL G3 VSL Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses similar terminology to that used in the associated requirement, and is therefore consistent with the requirement.
FERC VSL G4 VSL Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The VSL is based on a single violation and not cumulative violations.

VRF and VSL Justifications – PRC-005-4, R5	
Proposed VRF	**Medium**
NERC VRF Discussion	Failure to initiate resolution of an unresolved maintenance issue for a Protection System Component could directly affect the electrical state or the capability of the bulk power system. However, violation of this requirement is unlikely to lead to bulk power system instability, separation, or cascading failures. The applicable entities are always responsible for maintaining the reliability of the bulk power system regardless of the situation. This VRF emphasizes the risk to system performance that results from mal-performing Protection System Components. Failure to initiate resolution of an unresolved maintenance issue for a Protection System Component will not, by itself, lead to instability, separation, or cascading failures. Thus, the requirement meets NERC's criteria for a Medium VRF.
FERC VRF G1 Discussion	Guideline 1- Consistency w/ Blackout Report: N/A
FERC VRF G2 Discussion	Guideline 2- Consistency within a Reliability Standard: The requirement has no subpart(s); therefore, only one VRF was assigned and no conflict(s) exist.
FERC VRF G3 Discussion	Guideline 3- Consistency among Reliability Standards: The only requirement within approved Standards, PRC-004-2a Requirements R1 and R2 contain a similar requirement and is assigned a HIGH VRF. However, these requirements contain several subparts, and the VRF must address the most egregious risk related to these subparts, and a comparison to these requirements may be irrelevant. PRC-022-1 Requirement R1.5 contains only a similar requirement, and is assigned a MEDIUM VRF. FAC-003-2 Requirement R5 contains only a similar requirement, and is assigned a MEDIUM VRF.
FERC VRF G4 Discussion	Guideline 4- Consistency with NERC Definitions of VRFs: Failure to initiate resolution of an unresolved maintenance issue for a Protection System Component could directly affect the electrical state or the capability of the bulk power system.

VRF and VSL Justifications – PRC-005-4, R5			
Proposed VRF	**Medium**		
	However, violation of this requirement is unlikely to lead to bulk power system instability, separation, or cascading failures. The applicable entities are always responsible for maintaining the reliability of the bulk power system regardless of the situation. This VRF emphasizes the risk to system performance that results from mal-performing Protection System Components. Failure to initiate resolution of an unresolved maintenance issue for a Protection System Component will not, by itself, lead to instability, separation, or cascading failures. Thus, the requirement meets NERC's criteria for a Medium VRF.		
FERC VRF G5 Discussion	Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation: This requirement establishes a single risk-level, and the assigned VRF is consistent with that risk level.		
Proposed VSL – PRC-005-4, R5			
Lower	**Moderate**	**High**	**Severe**
The entity failed to undertake efforts to correct 5 or fewer identified Unresolved Maintenance Issues.	The entity failed to undertake efforts to correct greater than 5, but less than or equal to 10 identified Unresolved Maintenance Issues.	The entity failed to undertake efforts to correct greater than 10, but less than or equal to 15 identified Unresolved Maintenance Issues.	The entity failed to undertake efforts to correct greater than 15 identified Unresolved Maintenance Issues.

VRF and VSL Justifications – PRC-005X, R5	
NERC VSL Guidelines	Meets NERC's VSL Guidelines—There is an incremental aspect to the violation and the VSLs follow the guidelines for incremental violations.
FERC VSL G1 VSL Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The Requirement in PRC-005-4 is identical to that in PRC-005-3, which has identical VSLs.
FERC VSL G2 VSL Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single VSL Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: VSL Assignments that Contain Ambiguous Language	Guideline 2a: N/A Guideline 2b: The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.

VRF and VSL Justifications – PRC-005-4, R5	
FERC VSL G3 VSL Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses similar terminology to that used in the associated requirement, and is therefore consistent with the requirement.
FERC VSL G4 VSL Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The VSL is based on a single violation and not cumulative violations.

Exhibit H

Summary of Development History and Complete Record of Development

Exhibit H—Summary of the Reliability Standard Development Proceeding and Complete Record of Development of Proposed Reliability Standard PRC-005-4

The development record for proposed Reliability Standard PRC-005-4 is summarized below.

I. Overview of the Standard Drafting Team

When evaluating a proposed Reliability Standard, the Commission is expected to give "due weight" to the technical expertise of the ERO[1]. The technical expertise of the ERO is derived from the standard drafting team. For this project, the standard drafting team consisted of industry experts, all with a diverse set of experiences. A roster of the standard drafting team members is included in **Exhibit I**.

II. Standard Development History

A. Standard Authorization Request Development

The Standard Authorization Request ("SAR") was posted for a formal comment period from February 13, 2014 through March 14, 2014. The standards committee ("SC") approved the SAR on February 12, 2014.

B. First Posting- Comment Period, Ballot and Non-Binding Poll

Proposed Reliability Standard PRC-005-4 was posted for a 45- public comment period April 17, 2014 through June 3, 2014, with an initial ballot held from May 23, 2014 through June 3, 2014. Several documents were posted for guidance with the first draft, including the Unofficial Comment Form, SPCS Technical Report, FERC Order 758, and the NERC Response to NOPR. The initial ballot received a 85.42% quorum, and an

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[1] Section 215(d)(2) of the Federal Power Act; 16 U.S.C. §824(d) (2) (2012).

approval of 47.89%. The Non-Binding Poll achieved a 85.67% quorum and 47.77% of supportive opinions. There were 56 sets of responses, including comments from approximately 166 individuals from approximately 177 companies, representing all 10 industry segments.

The SDT considered stakeholder comments regarding proposed Reliability Standard PRC-005-4 and made the following observations and modifications based on those comments:

- Changes were made to the headers of Table 1-5 and Table 2 to direct attention to Table 5 for the maintenance activities associated with Sudden Pressure Relaying Components.
- Clarifying not added to the header of Table 5.
- Revised the FAQ concerning the testing of the sensing mechanism of sudden pressure relays.
- Correction was made to 4.2.7 in the Supplementary Reference and FAQ document.
- The term “Part” was deleted from the Administrative section.
- Changes were made to the write-ups to provide additional clarity within the Supplementary Reference and FAQ document.
- Revised section 4.2.6.1 of the Applicability to address situations where Balancing Authorities participate in a Reserve Sharing Group.
- Modified 4.2.6.1 to include the Reserve Sharing Group.
- Modified Footnote #1, Page 4 to include the Reserve Sharing Group.
- Modified Requirement 3, Part 3.1 and 3.1.1 to include the Reserve Sharing Group.
- Modified Requirement 4, Part 4.1 and 4.1.1 to include the Reserve Sharing Group.
- Added Sudden Pressure Relaying to Applicability Section 4.2.5.3.
- Added Sudden Pressure Relaying to Applicability Section 4.2.5.
- Parts of Requirement R3 and R4 and sub-parts 3.1.1 and 3.1.2 was removed.
- Included language in the standard that was originally in the implementation plan that required completion of maintenance activities within three years for newly-identified Automatic Reclosing Components following a notification under Requirement R6, which has been removed.
- Requirement R3 and R4 3.1, 4.1 and their subparts have been removed, and have not been reinserted into the implementation plan.
- Requirement R6 and all associated references to Requirement R6 were removed from the standard.

- Added language within Data Retention to account for those cases where the maintenance intervals are longer than the audit period as well as where the maintenance intervals are shorter than the audit period.
- Corrected Requirement R6 references Section 4.2.7 in Footnote #1.

C. Second Posting- Comment Period, Additional Ballot and Non-Binding Poll

Proposed Reliability Standard PRC-005-4 was posted for a 45- day public comment period from July 30, 2014 through September 12, 2014, with an additional ballot from September 3, 2014 through September 12, 2014. The additional ballot achieved a 84.33% quorum, and an approval of 76.03%. The Non-Binding Poll achieved a 84.81% quorum and 74.00% of supportive opinions. There were 47 sets of responses, including comments from approximately 116 individuals from approximately 82 companies, representing all 10 industry segments.

The SDT considered stakeholder comments regarding proposed Reliability Standard PRC-005-4 and made the following observations and modifications based on those comments:

- Modified applicability section 4.2.4 for clarity within RAS definition.
- Removed redline from Requirement R6.
- Added the word "unmonitored" to Table 5 for clarification.
- Added Requirement R5 evidence retention language to the Evidence Retention section.

D. Final Ballot

Proposed Reliability Standard PRC-005-4 was posted for a 10-day public comment period from October 20, 2014 through October 29, 2014. The proposed Reliability Standard received a quorum of 88.25% and an approval of 74.14%.

E. Board of Trustees Adoption

Proposed Reliability Standard PRC-005-4 was adopted by the NERC Board of Trustees on November 13, 2014.

Project 2007-17.3 (PRC-005-X) Protection System Maintenance and Testing - Phase 3 (Sudden Pressure Relays)

Related Files

Status

A final ballot for **PRC-005-4 - Protection System, Automatic Reclosing, and Sudden Pressure Relaying Maintenance** concluded at **8 p.m. Eastern on Wednesday, October 29, 2014**. The ballot results can be accessed via the links below. The standard documents will be submitted to the Board of Trustees for adoption and then filed with the appropriate regulatory authorities.

Background:

Project 2007-17.3 (PRC-005-X) will address a directive from FERC Order No. 758, which accepted NERC's proposal to develop a technical document, in lieu of a prescriptive FERC directive, that will provide the following information:

(1) describe the devices and functions (to include sudden pressure relays which trip for fault conditions) that should address FERC's concern; and

(2) propose minimum maintenance activities for such devices and maximum maintenance intervals, including the technical basis for each.

In Order No. 758, the Commission accepted NERC's proposal, by stating as follows:

NERC states that these technical documents will address those protective relays that are necessary for the reliable operation of the Bulk-Power System and will allow for differentiation between protective relays that detect faults from other devices that monitor the health of the individual equipment and are advisory in nature (e.g., oil temperature). Following development of the above-referenced document(s), NERC states that it will "propose a new or revised standard (e.g. PRC-005) using the NERC Reliability Standards development process to include maintenance of such devices, including establishment of minimum maintenance activities and maximum maintenance intervals." Accordingly, NERC proposes to "add this issue to the Reliability Standards issues database for inclusion in the list of issues to address the next time the PRC-005 standard is revised."

The Commission accepts NERC's proposal, and directs NERC to file, within sixty days of publication of this Final Rule, a schedule for informational purposes regarding the development of the technical documents referenced above, including the identification of devices that are designed to sense or take action against any abnormal system condition that will affect reliable operation. NERC shall include in the informational filing a schedule for the development of the changes to the standard that NERC stated it would propose as a result of the above-referenced documents. NERC should update its schedule when it files its annual work plan.

As a follow-up to this Commission ruling, the Planning Committee studied sudden pressure relays and issued the attached report, which recommends moving ahead with a Standard. Specifically, the System Protection and Control Subcommittee (SPCS) completed a technical report recommending that a standard drafting team modify PRC-005 to explicitly address maintenance and testing of the actuator device of the sudden pressure relay when applied as a protective device that trips a facility described in the applicability section of the Reliability Standard. Additionally, the standard drafting team (SDT) intends to consider changes to the standard that provide consistency and alignment with other Reliability Standards. Lastly, the standards drafting team intends to modify the standard to address any directives issued by FERC related to the approval of PRC-005-3, which is pending filing with FERC

Draft	Actions	Dates	Results	Consideration of Comments
Final PRC-005-4 Clean (38)| Redline to Last Posting (39) PRC-005-4 to approved PRC-005-3 (40) Implementation Plan Clean (41) | Redline to Last Posting (42) **Supporting Documents:** Supplementary Reference Document Clean (43) | Redline (44) VRF/VSL Justification (45)	Final Ballot Info>> (46) Vote>>	10/20/14 – 10/29/14 (Closed)	Summary>> (47) Ballot Results>> (48)	

PRC-005-X Clean (22) | Redline to Last Posting (23) Implementation Plan Clean (24) | Redline to Last Posting (25) **Supporting Documents:** Unofficial Comment Form (Word) (26) Supplementary Reference Document Clean (27) | Redline (28)	Additional Ballot and Non-Binding Poll Updated Info>> (29) Info>> (30) Vote>>	09/03/14 – 09/12/14 (Closed)	Summary>> (32) Ballot Results>> (33) Non-Binding Poll Results>> (34)	Consideration of Comments>> (36) Additional Comments Clarification>> (37)
	Comment Period Info>> (31) Submit Comments>>	07/30/14 – 09/12/14 (Closed)	Comments Received>> (35)	
PRC-005-X Clean (7) | Redline to Last Posting (8) Implementation Plan Clean (9) | Redline to Last Posting (10) **Supporting Documents:** Unofficial Comment Form (Word) (11) Supplementary Reference Document Clean (12) | Redline (13)	Ballot and Non-binding Poll Updated Info>> (14) Info>> (15) Vote>>	05/23/14 - 06/03/14 (Closed)	Summary>> (17) Ballot Results>> (18) Non-Binding Poll Results>> (19)	
	Comment Period Info>> (16) Submit Comments>>	04/17/14 – 06/03/14 (Closed)	Comments Received>> (20)	Consideration of Comments>> (21)
	Join Ballot Pool>>	04/17/14 – 05/16/14		

		(Closed)		
Standard Authorization Request (1) **Supporting Documents:** Unofficial Comment Form (Word) (2) SPCS Technical Report (3) FERC Order 758 (4) NERC Response to NOPR (5)	Comment Period Info>> (6) Submit Comments>>	02/13/14 - 03/14/14 (Closed)		

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Standards Authorization Request Form

When completed, email this form to:
Valerie.Agnew@nerc.net

For questions about this form or for assistance in completing the form, call Valerie Agnew at 404-446-2566.

NERC welcomes suggestions for improving the reliability of the Bulk-Power System through improved Reliability Standards. Please use this form to submit your proposal for a new NERC Reliability Standard or a revision to an existing standard.

Request to propose a new or a revision to a Reliability Standard			
Proposed Standard:	PRC-005-4		
Date Submitted:	2/12/2014		
SAR Requester Information			
Name:	Charles Rogers		
Organization:	Protection System Maintenance Standard Drafting Team		
Telephone:	517-788-0027	E-mail:	Charles.Rogers@cmsenergy.com
SAR Type (Check as many as applicable)			
☐ New Standard		☐ Withdrawal of existing Standard	
☒ Revision to existing Standard		☐ Urgent Action	

SAR Information

Industry Need (What is the industry problem this request is trying to solve?):

The Federal Energy Regulatory Commission, in paragraphs 11-15 of Order No. 758, accepted NERC's proposal to "develop, either independently or in association with other technical organizations such as IEEE, one or more technical documents which:

1. describe the devices and functions (to include sudden pressure relays which trip for fault conditions) that should address FERC's concern; and
2. propose minimum maintenance activities for such devices and maximum maintenance intervals, including the technical basis for each."

NERC is following through on its commitment to "propose a new or revised standard (e.g. PRC-005) using the NERC Reliability Standards development process to include maintenance of such devices, including establishment of minimum maintenance activities and maximum maintenance intervals." FERC also directed NERC to file an informational filing with a schedule for the development of the changes to the standard.

The NERC System Protection and Control Subcommittee has subsequently issued a technical paper entitled "Sudden Pressure Relays and Other Devices that Respond to Non-Electrical Quantities". The SPCS recommended the following guidance to address the concerns stated in FERC Order No. 758:

"Modify PRC-005 to explicitly address maintenance and testing of the actuator device of the sudden pressure relay when applied as a protective device that trips a facility described in the applicability section of the Reliability Standard.

- Develop minimum maintenance activities for sudden pressure relays similar to Table 1-1: Protective Relay. Based on the survey results, the SPCS recommends the maximum interval for time-based maintenance programs be 6 years.
- Modify Table 1-5: Control Circuitry Associated With Protective Functions to explicitly include the sudden pressure control circuitry."

In addition to the above need to address sudden pressure relays, during the development of PRC-005-3, several commenters raised concerns that there is no obligation for the Balancing Authority (BA) to provide the essential data (the largest BES generating unit within the BA area, per Applicability section 4.2.6.1 of PRC-005-3) for the responsible entities to implement PRC-005-3. Modifying the Applicability of PRC-005-2 was determined to be outside the scope of the PRC-005-3 SAR; consequently, the issue was placed in the NERC Issues Database for consideration during the development of PRC-005-4, and therefore is set forth in this SAR to ensure it is within its scope.

SAR Information
SAR Information
Industry Need (What is the industry problem this request is trying to solve?):
Also, during the development of NERC Reliability Standard PRC-025-1, a possible inconsistency between that standard and PRC-005-2 was identified regarding the applicability of generator station service transformers. This issue will be considered during the development of PRC-005-4. Additionally, the SDT will review the standard to determine if any modifications are necessary to align the standard with changes made to other NERC Reliability Standards, the BES definition, and any other developments that followed the NERC BOT adoption of PRC-005-2 and PRC-005-3. Finally, NERC staff has requested that possible alternatives to the 24-year record retention period be evaluated by the SDT. During the consideration of PRC-005-2, the Office of Management and Budget requested additional support for the lengthy retention period. Possible solutions include modifying the measures in Section C 'Measures' or the evidence retention in Section D 'Compliance' of the standard. Modifying the standard as set forth will promote the reliable operation of the Bulk Electric System (BES) by: assuring that sudden pressure relays are properly maintained so they may be expected to perform properly; assuring that the Applicability section of PRC-005-4 accurately reflects the relevant Functional Entities and Facilities; improving consistency with other Reliability Standards and the BES definition. No market interface impacts are anticipated.

SAR Information
Purpose or Goal (How does this request propose to address the problem described above?):
The definition of Protection System may be revised, or a new definition created that describes the relays becoming applicable to the revised standard. The Applicability section of the standard may be modified to: 1) describe explicitly those sudden pressure relays that must be maintained in accordance with the revised standard; 2) include Balancing Authorities; and 3) provide consistency with other Reliability Standards and the BES definition. The tables of minimum maintenance activities and maximum maintenance intervals will be modified or added to include appropriate intervals and activities for sudden pressure relays. The SDT shall consider possible alternatives to the 24-year record retention period in PRC-005-3. Possible solutions include modifying the measures in Section C ‘Measures’ or the evidence retention in Section D ‘Compliance’. The SDT shall consider modifications, as needed, to address any FERC directives that may result from the Commission’s consideration of PRC-005-3, which is pending regulatory approval. Finally, the Supplementary Reference Document (provided as a technical reference for PRC-005-3) should be modified to provide the rationale for the maintenance activities and intervals within the revised standard, as well as to provide application guidance to industry.
Identify the Objectives of the proposed standard’s requirements (What specific reliability deliverables are required to achieve the goal?):
Successful implementation of the revised standard will assure that the sudden pressure relays will perform as needed for the conditions anticipated by those performance requirements.
Brief Description (Provide a paragraph that describes the scope of this standard action.)
The Standard Drafting Team (SDT) shall modify NERC Standard PRC-005-3 to explicitly address the maintenance of sudden pressure relays that trip a facility as described in the Applicability section of the Reliability Standard. The SDT shall also consider changes to the standard that provide consistency and alignment with other Reliability Standards. Additionally, the SDT shall modify the standard to address any directives issued by FERC related to the approval of PRC-005-3.

SAR Information
Detailed Description (Provide a description of the proposed project with sufficient details for the standard drafting team to execute the SAR. Also provide a justification for the development or revision of the standard, including an assessment of the reliability and market interface impacts of implementing or not implementing the standard action.)
The drafting team shall: 1. Consider revising the title of the standard to appropriately include sudden pressure relays. 2. Consider modifying the Purpose of the standard as necessary to address sudden pressure relays. 3. Consider revising the definition of Protection System, or creating a new definition for the applicable sudden pressure relays. 4. Modify the Applicability section of the standard as necessary. 5. Revise or add requirements as necessary. 6. Modify or create additional tables within the standard to include maximum intervals and minimum activities appropriate for the devices being addressed, with consideration for the technology of the devices and for any condition monitoring that may be in place for those devices. 7. Modify the measures and Violation Severity Levels as necessary to address the modified requirements. 8. Modify Section C ‘Measures’ or Section D ‘Compliance’ of the standard, as needed, to address the 24-year record retention issue. 9. Consider modifications as needed to address any FERC directives that may result from the Commission’s consideration of PRC-005-3. 10. Revise the implementation elements for PRC-005-2 and PRC-005-3 as needed to assure consistent and systematic implementation. 11. Modify the informative Supplementary Reference Document (provided as a technical reference for PRC-005-3) to provide the rationale for the maintenance activities and intervals within the modified standard, as well as to provide application guidance to industry.

Reliability Functions		
The Standard will Apply to the Following Functions (Check each one that applies.)		
☐	Regional Reliability Organization	Conducts the regional activities related to planning and operations, and coordinates activities of Responsible Entities to secure the reliability of the Bulk Electric System within the region and adjacent regions.
☐	Reliability Coordinator	Responsible for the real-time operating reliability of its Reliability Coordinator Area in coordination with its neighboring Reliability Coordinator's wide area view.
☒	Balancing Authority	Integrates resource plans ahead of time, and maintains load-interchange-resource balance within a Balancing Authority Area and supports Interconnection frequency in real time.
☐	Interchange Authority	Ensures communication of interchange transactions for reliability evaluation purposes and coordinates implementation of valid and balanced interchange schedules between Balancing Authority Areas.
☐	Planning Coordinator	Assesses the longer-term reliability of its Planning Coordinator Area.
☐	Resource Planner	Develops a >one year plan for the resource adequacy of its specific loads within a Planning Coordinator area.
☐	Transmission Planner	Develops a >one year plan for the reliability of the interconnected Bulk Electric System within its portion of the Planning Coordinator area.
☐	Transmission Service Provider	Administers the transmission tariff and provides transmission services under applicable transmission service agreements (e.g., the pro forma tariff).
☒	Transmission Owner	Owns and maintains transmission facilities.
☐	Transmission Operator	Ensures the real-time operating reliability of the transmission assets within a Transmission Operator Area.
☒	Distribution Provider	Delivers electrical energy to the End-use customer.
☒	Generator Owner	Owns and maintains generation facilities.
☐	Generator Operator	Operates generation unit(s) to provide real and reactive power.

Reliability Functions		
The Standard will Apply to the Following Functions (Check each one that applies.)		
☐	Purchasing-Selling Entity	Purchases or sells energy, capacity, and necessary reliability-related services as required.
☐	Market Operator	Interface point for reliability functions with commercial functions.
☐	Load-Serving Entity	Secures energy and transmission service (and reliability-related services) to serve the End-use Customer.

Reliability and Market Interface Principles	
Applicable Reliability Principles (Check all that apply).	
☒	1. Interconnected bulk power systems shall be planned and operated in a coordinated manner to perform reliably under normal and abnormal conditions as defined in the NERC Standards.
☐	2. The frequency and voltage of interconnected bulk power systems shall be controlled within defined limits through the balancing of real and reactive power supply and demand.
☐	3. Information necessary for the planning and operation of interconnected bulk power systems shall be made available to those entities responsible for planning and operating the systems reliably.
☐	4. Plans for emergency operation and system restoration of interconnected bulk power systems shall be developed, coordinated, maintained and implemented.
☒	5. Facilities for communication, monitoring and control shall be provided, used and maintained for the reliability of interconnected bulk power systems.
☐	6. Personnel responsible for planning and operating interconnected bulk power systems shall be trained, qualified, and have the responsibility and authority to implement actions.
☐	7. The security of the interconnected bulk power systems shall be assessed, monitored and maintained on a wide area basis.
☐	8. Bulk power systems shall be protected from malicious physical or cyber attacks.

Does the proposed Standard comply with all of the following Market Interface Principles?	Enter (yes/no)
1. A reliability standard shall not give any market participant an unfair competitive advantage.	Yes
2. A reliability standard shall neither mandate nor prohibit any specific market structure.	Yes

Reliability and Market Interface Principles	
Does the proposed Standard comply with all of the following Market Interface Principles?	Enter (yes/no)
3. A reliability standard shall not preclude market solutions to achieving compliance with that standard.	Yes
4. A reliability standard shall not require the public disclosure of commercially sensitive information. All market participants shall have equal opportunity to access commercially non-sensitive information that is required for compliance with reliability standards.	Yes

Related Standards	
Standard No.	Explanation

Related SARs	
SAR ID	Explanation

Regional Variances	
Region	Explanation
ERCOT	
FRCC	
MRO	
NPCC	
RFC	
SERC	
SPP	
WECC	

Unofficial Comment Form

Project 2007-17.3 Phase 3 of Protection System Maintenance and Testing (Sudden Pressure Relays)
Standard Authorization Request for PRC-005-4

Please **DO NOT** use this form for submitting comments. Please use the electronic form to submit comments on the Standard Authorization Request (SAR). The electronic comment form must be completed by **8 p.m. ET, March 14, 2014.**

If you have questions please contact Jordan Mallory via email or by telephone at 404-446-9733.

The project page may be accessed by clicking here.

Background Information

This posting is soliciting informal comment.

Project 2007-17.3 (PRC-005-4) will address a directive from FERC Order No. 758, which accepted NERC's proposal to develop a technical document, in lieu of a prescriptive FERC directive, that will provide the following information:

(1) Describe the devices and functions (to include sudden pressure relays which trip for fault conditions) that should address FERC's concern; and

(2) Propose minimum maintenance activities for such devices and maximum maintenance intervals, including the technical basis for each.

In Order No. 758, the Commission accepted NERC's proposal, by stating as follows:

> NERC states that these technical documents will address those protective relays that are necessary for the reliable operation of the Bulk-Power System and will allow for differentiation between protective relays that detect faults from other devices that monitor the health of the individual equipment and are advisory in nature (e.g., oil temperature). Following development of the above-referenced document(s), NERC states that it will "propose a new or revised standard (e.g. PRC-005) using the NERC Reliability Standards development process to include maintenance of such devices, including establishment of minimum maintenance activities and maximum maintenance intervals." Accordingly, NERC proposes to "add this issue to the Reliability Standards issues database for inclusion in the list of issues to address the next time the PRC-005 standard is revised."

> The Commission accepts NERC's proposal, and directs NERC to file, within sixty days of publication of this Final Rule, a schedule for informational purposes regarding the development of the technical documents referenced above, including the identification of devices that are designed to sense or take action against any abnormal system condition that will affect reliable operation. NERC shall include in the informational filing a schedule for the development of the changes to the standard that NERC stated it would propose as a result of the above-referenced documents. NERC should update its schedule when it files its annual work plan.

As a follow-up to this Commission ruling, the Planning Committee studied sudden pressure relays and issued a technical report, which recommends moving ahead with a Standard. Specifically, the System Protection and Control Subcommittee (SPCS) completed a technical report recommending that a standard drafting team modify PRC-005 to explicitly address maintenance and testing of the actuator device of the sudden pressure relay when applied as a protective device that trips a facility described in the applicability section of the Reliability Standard. The Sudden pressure Relays and Other Devices that Respond to Non-Electrical Quantities Technical Report may be accessed by clicking here. Additionally, the standard drafting team (SDT) intends to consider changes to the standard that provide consistency and alignment with other Reliability Standards. Lastly, the standards drafting team intends to modify the standard to address any directives issued by FERC related to the approval of PRC-005-3, which is pending filing with FERC.

Questions

You do not have to answer all questions. Enter comments in simple text format. Bullets, numbers, and special formatting will not be retained.

1. Do you have any specific questions or comments relating to the scope of the proposed SAR?

   ☐ Yes
   ☐ No
   Comments:

2. If you are aware of the need for a regional variance or business practice that should be considered with this phase of the project, please identify it here.

   ☐ Yes
   ☐ No
   Comments:

3. If you have any other comments on this SAR that you haven't already mentioned, please provide them here:

   Comments:

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Sudden Pressure Relays and Other Devices that Respond to Non-Electrical Quantities

SPCS Input for Standard Development in Response to FERC Order No. 758

System Protection and Control Subcommittee

December 2013

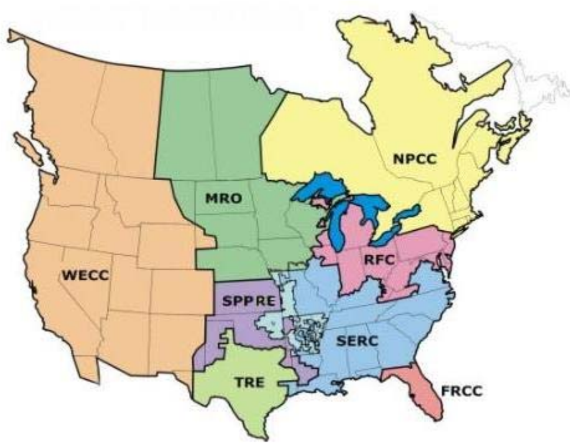
RELIABILITY | ACCOUNTABILITY

3353 Peachtree Road NE
Suite 600, North Tower
Atlanta, GA 30326
404-446-2560 | www.nerc.com

NERC's Mission

The North American Electric Reliability Corporation (NERC) is an international regulatory authority established to enhance the reliability of the Bulk-Power System in North America. NERC develops and enforces Reliability Standards; assesses adequacy annually via a ten-year forecast and winter and summer forecasts; monitors the Bulk-Power System; and educates, trains, and certifies industry personnel. NERC is the electric reliability organization for North America, subject to oversight by the U.S. Federal Energy Regulatory Commission (FERC) and governmental authorities in Canada.[1]

NERC assesses and reports on the reliability and adequacy of the North American Bulk-Power System, which is divided into eight Regional areas, as shown on the map and table below. The users, owners, and operators of the Bulk-Power System within these areas account for virtually all the electricity supplied in the U.S., Canada, and a portion of Baja California Norte, México.



Note: The highlighted area between SPP RE and SERC denotes overlapping Regional area boundaries. For example, some load serving entities participate in one Region and their associated transmission owner/operators in another.

NERC Regional Entities	
FRCC Florida Reliability Coordinating Council	**SERC** SERC Reliability Corporation
MRO Midwest Reliability Organization	**SPP RE** Southwest Power Pool Regional Entity
NPCC Northeast Power Coordinating Council	**TRE** Texas Reliability Entity
RFC ReliabilityFirst Corporation	**WECC** Western Electricity Coordinating Council

[1] As of June 18, 2007, the U.S. Federal Energy Regulatory Commission (FERC) granted NERC the legal authority to enforce Reliability Standards with all U.S. users, owners, and operators of the bulk power system, and made compliance with those standards mandatory and enforceable. In Canada, NERC presently has memorandums of understanding in place with provincial authorities in Ontario, New Brunswick, Nova Scotia, Québec, and Saskatchewan, and with the Canadian National Energy Board. NERC standards are mandatory and enforceable in Ontario and New Brunswick as a matter of provincial law. NERC has an agreement with Manitoba Hydro making reliability standards mandatory for that entity, and Manitoba has recently adopted legislation setting out a framework for standards to become mandatory for users, owners, and operators in the province. In addition, NERC has been designated as the "electric reliability organization" under Alberta's Transportation Regulation, and certain reliability standards have been approved in that jurisdiction; others are pending. NERC and NPCC have been recognized as standards-setting bodies by the Régie de l'énergie of Québec, and Québec has the framework in place for reliability standards to become mandatory. NERC's reliability standards are also mandatory in Nova Scotia and British Columbia. NERC is working with the other governmental authorities in Canada to achieve equivalent recognition.

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This technical document was approved by the NERC Planning Committee on December 11, 2013.

Executive Summary

In Order No. 758, FERC directed NERC to identify ". . . devices that are designed to sense or take action against any abnormal system condition that will affect reliable operation [of the Bulk-Power System]." In response to this directive, the Standards Committee requested the SPCS develop a technical report to support development of modifications to NERC Reliability Standard PRC-005, Protection System Maintenance and Testing. This report to the NERC Planning Committee (PC) addresses issues raised in the order regarding devices that respond to non-electrical quantities in general, and specifically sudden pressure relays. Upon PC approval, this report will be forwarded to the NERC Standards Committee to support a standard drafting team that will modify the existing standard or develop a new standard.

In developing this report, the SPCS evaluated all devices on the IEEE list of device numbers to identify which devices that respond to non-electrical quantities may impact reliable operation of the Bulk-Power System. As a result of this analysis, the SPCS concludes the only devices responding to non-electrical quantities that should be included in the applicability of PRC-005 are sudden pressure relays utilized in a tripping function. When applied in a tripping function, these devices initiate actions to clear faults to support reliable operation of the Bulk-Power System. The other devices evaluated respond to abnormal equipment conditions and take action to protect equipment from mechanical or thermal damage, or premature loss of life, rather than for the purpose of initiating fault clearing or mitigating an abnormal system condition to support reliable operation of the Bulk-Power System.

Based on its conclusion, the SPCS assessed existing industry practices for maintenance and testing of sudden pressure relays and conducted an informal industry survey to develop recommendations for maintenance and testing requirements to be included in PRC-005. To validate its approach, the SPCS contacted the following entities for their feedback: the IEEE Power System Relaying Committee, the NATF System Protection Practices Group, and the EPRI Generator Owner/Operator Technical Focus Group. All three of these organizations indicated the results of the SPCS survey are consistent with their respective experiences.

Considering its analysis and conclusion, the SPCS recommends the following guidance for future development of NERC Reliability Standard PRC-005, Protection System Maintenance, to address the concerns stated in FERC Order No. 758.

Modify PRC-005 to explicitly address maintenance and testing of the actuator device of the sudden pressure relay when applied as a protective device that trips a facility described in the applicability section of the Reliability Standard.

- Develop minimum maintenance activities for sudden pressure relays similar to Table 1-1: Protective Relay. Based on the survey results, the SPCS recommends the maximum interval for time-based maintenance programs be 6 years.
- Modify Table 1-5: Control Circuitry Associated With Protective Functions to explicitly include the sudden pressure control circuitry.

Introduction

Overview

In Order No. 758, FERC directed NERC to identify ". . . devices that are designed to sense or take action against any abnormal system condition that will affect reliable operation [of the Bulk-Power System]." In response to this directive, the Standards Committee requested the SPCS develop a technical report to support development of modifications to NERC Reliability Standard PRC-005, Protection System Maintenance and Testing. This report to the NERC Planning Committee (PC) addresses issues raised in the order regarding devices that respond to non-electrical quantities in general, and specifically sudden pressure relays.[2] Upon PC approval, this report will be forwarded to the NERC Standards Committee to support a standard drafting team that will modify the existing standard or develop a new standard.

Background

FERC Order No. 758 is associated with an interpretation of NERC Reliability Standard PRC-005-1, Protection System Maintenance and Testing. The interpretation addressed a series of questions submitted by the Regional Entities Compliance Monitoring Processes Working Group. The questions sought interpretation of whether specific components must be included in a maintenance and testing program. Specifically, the questions pertained to battery chargers, auxiliary relays and sensing devices, reclosing relays, dc circuitry, and communications systems.

In the order, FERC approved the interpretation as it pertains to the text of the existing standard and relevant defined terms in the NERC glossary. However, FERC identified concerns with certain devices that may impact reliability of the Bulk-Power System and directed that NERC address these concerns as specified in the order. The concerns specified in the order pertain to reclosing relays and to sudden pressure relays and other devices that respond to non-electrical quantities. Concerns related to maintenance and testing of reclosing relays are addressed in a separate, joint report of the NERC System Analysis and Modeling Subcommittee (SAMS) and the SPCS. This report focuses on the directive in the order pertaining to sudden pressure relays and other devices that respond to non-electrical quantities.

In the Notice of Proposed Rulemaking (NOPR) associated with this interpretation, FERC noted a concern that the proposed interpretation may not include all components that serve in some protective capacity. FERC further noted its concerns included the exclusion of auxiliary and non-electrical sensing relays. FERC proposed to direct NERC to develop a modification to Reliability Standard PRC-005-1 to include any component or device that is designed to detect defective lines or apparatuses or other power system conditions of an abnormal or dangerous nature, including devices designed to sense or take action against any abnormal system condition that will affect reliable operation, and to initiate appropriate control circuit actions.

In its comments on the NOPR, NERC noted that the revised definition of protection system and changes to PRC-005-1, in progress at that time, address FERC's concerns pertaining to auxiliary relays.[3] NERC also acknowledged FERC concerns related to protective relays that do not respond to electrical quantities and agreed that sudden pressure relays which trip for fault conditions should be maintained in accordance with NERC Reliability Standard requirements. However, NERC noted concern that the scope of the proposed directive was so broad that any device that is installed on the Bulk-Power System to monitor conditions in any fashion may be included. NERC further noted that, in fact, many of these devices are advisory in nature and should not be reflected within NERC standards if they do not serve a necessary reliability purpose.

NERC therefore proposed to develop, either independently or in association with other technical organizations such as IEEE, one or more technical documents which:

i. describe the devices and functions (to include sudden pressure relays which trip for fault conditions) that should address FERC's concern; and

ii. propose minimum maintenance activities for such devices and maximum maintenance intervals, including the technical basis for each.

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[2] Order No. 758 used the term sudden pressure relays, which the SPCS has interpreted to refer to the general class of relays responding to pressure, including sudden pressure, rapid pressure rise, and Buchholz relays.

[3] The changes referenced by NERC are included in PRC-005-2, adopted by the NERC Board of Trustees on November 7, 2012 and filed with a petition to FERC on February 26, 2013.

NERC stated that these technical documents will address those protective relays that are necessary for the reliable operation of the Bulk-Power System and will allow for differentiation between protective relays that detect faults from other devices that monitor the health of the individual equipment and are advisory in nature (e.g., oil temperature). Following development of the above-referenced document(s), NERC will propose a new or revised standard (e.g., PRC-005) using the NERC Reliability Standards development process to include maintenance of such devices, including establishment of minimum maintenance activities and maximum maintenance intervals.

In Order No. 758, FERC accepted the NERC proposal, and directed NERC to file, within sixty days of publication of the Final Rule, a schedule for informational purposes regarding the development of the technical documents referenced above, including the identification of devices that are designed to sense or take action against any abnormal system condition that will affect reliable operation. The SPCS has previously provided information regarding the schedule and steps planned to develop the proposed documents and this information was included in an informational filing on April 12, 2012 (see Appendix A). In accordance with the filed schedule, this report is submitted for approval to the Planning Committee to support standard development beginning in the first quarter of 2014.

Chapter 1 – Devices that Respond to Non-Electrical Quantities

Considerations for Inclusion in PRC-005

The SPCS considered the risk to reliable operation of the Bulk-Power System when developing a basis for identifying devices that should be included in the maintenance and testing standard. The following criteria were evaluated:

- <u>Action taken</u>: The SPCS considered the criticality of the effect of the action taken on system reliability, noting that tripping equipment is typically initiated when such action is necessary for reliability, although differentiation is necessary between tripping equipment to support reliable operation of the Bulk-Power System versus tripping to minimize the impact of abnormal operating conditions on a specific element. The SPCS also noted that initiating an alarm implies there is time for operator intervention to alleviate an adverse impact, and that initiating a control action implies immediate isolation of equipment (i.e., tripping) is not necessary.
- <u>The risk associated with misoperation for an inadvertent operation or a failure to operate</u>: The SPCS concluded that evaluating the impact on system reliability must consider the impact of both a failure of the device to operate when its operation is required (a dependability-related failure) and an inadvertent operation (a security-related failure).
- <u>The risk of inadvertent operation during a disturbance</u>: The SPCS considered the risk of a device inadvertently operating in response to a system disturbance and causing or contributing to a cascading event. Devices that respond to quantities directly associated with an abnormal condition are typically more secure than devices that monitor quantities indirectly associated with the abnormal condition. Furthermore, devices that respond to quantities associated with an abnormal equipment condition are typically unaffected by conditions experienced during system disturbances, and thus, are much less prone to inadvertent operation during a disturbance than relays that respond to electrical quantities.

Basis for Evaluation

The SPCS considered the above alternatives and identified the attributes important to assessing the potential for a device to affect reliability of the Bulk-Power System. After consideration of the attributes identified, the SPCS determined the best approach for performing an assessment was to group all device types into one of three categories to differentiate the risk to reliable operation of the Bulk-Power System. The three categories are listed in order of decreasing potential for risk to Bulk-Power System reliability. Of these, the first category is deemed to present a risk to Bulk-Power System reliability that is sufficient to include maintenance and testing of the device in PRC-005.

(1) Devices that initiate actions to clear faults or mitigate abnormal system conditions to support reliable operation of the Bulk-Power System,

(2) Devices that initiate action for abnormal equipment conditions for purposes other than supporting reliable operation of the Bulk-Power System, and

(3) Devices that monitor the health of the individual equipment and provide information that is advisory in nature.

Analysis of Individual Devices

The SPCS used the list of IEEE device numbers as a starting point for its assessment to assure that all possible devices responding to non-electrical quantities were considered. A list of all IEEE device numbers, including a description of each device is included in Appendix B.

To address the concern identified in Order No. 758, the SPCS used a two-step process to identify devices that initiate actions to clear faults or mitigate abnormal system conditions to support reliable operation of the Bulk-Power System.

In the first step, the SPCS identified devices already addressed as a result of the revised definition of Protection System or that are clearly not protective devices, such as primary equipment and control devices. The initial categorization of devices from this first step is documented in Appendix C. The SPCS used the following criteria to eliminate such devices and develop a short list of devices requiring detailed analysis.

- Protective relay already addressed in PRC-005-2: Maintenance and testing requirements are already established for these devices and no further consideration is required.
- Auxiliary relay already addressed in PRC-005-2: Maintenance and testing requirements are already established for these devices and no further consideration is required.
- Autoreclosing and synchronism check relays: Maintenance and testing considerations for these devices are proposed in a separate report to address the directive in paragraph 27 of Order No. 758[4]; these devices do not require further consideration in this report.
- Primary equipment: Devices such as governors, valves, motors, and circuit breakers are primary equipment, rather than protective devices, and do not require further consideration.
- Control device: Devices such as position switches, contactors, and field application relays that are used for starting, stopping, or otherwise controlling operation of equipment, respond to manual input or signals directly associated with operation of the equipment. These devices may be separate from, or an integral part of, the controlled equipment. Control systems are excluded from maintenance and testing requirements in PRC-005.

In the second step, the SPCS evaluated each device on the short list to group them into one of the three categories. The short list of devices and the SPCS evaluation of each device are included in Appendix D. The list includes a description of each device, whether the device trips a power system element and, if so, the potential risk to the Bulk-Power System based on the preceding criteria. Classification of devices on the short list is presented in Table 1. Some devices appear in more than one category; e.g., some devices may be used to alarm or to isolate equipment, depending on the application and the practices that entities have developed specific to their circumstances.

As a result of the analysis, the SPCS concludes that sudden pressure relays that are utilized in a trip application should be included in the Protection System Maintenance and Testing standard. Recommendations for minimum maintenance activities and maximum intervals are discussed in the next section of this report.

[4] The SPCS recommended modifications to PRC-005 to explicitly address maintenance and testing of autoreclosing relays applied as an integral part of a SPS, and autoreclosing relays at or in proximity to certain generating plants. See *Considerations for Maintenance and Testing of Autoreclosing Schemes*, NERC System Analysis and Modeling Subcommittee and System Protection and Control Subcommittee, November 2012.

Table 1: Classification of Devices		
Initiate Actions to Clear Faults or Mitigate Abnormal System Conditions to Support Reliable Operation of the Bulk-Power System	**Initiate Action for Abnormal Equipment Conditions for Purposes other than Supporting Reliable Operation of the Bulk-Power System**	**Monitor the Health of Individual Equipment and Provide Information that is Advisory in Nature**
Sudden Pressure (63) (when utilized in a trip application)	• Overspeed Device (12) • Underspeed Device (14) • Apparatus Thermal Device (26) • Flame Detector (28) • Bearing Protective Device (38) • Mechanical Condition Monitor (39) • Atmospheric Condition Monitor (45) • Machine or Transformer Thermal Relay (49) • Density Switch or Sensor (61) • Pressure Switch (63) (other than sudden pressure relays utilized in trip application • Level Switch (71)	• Apparatus Thermal Device (26) • Bearing Protective Device (38) • Mechanical Condition Monitor (39) • Atmospheric Condition Monitor (45) • Machine or Transformer Thermal Relay (49) • Density Switch or Sensor (61) • Pressure Switch (63) (other than sudden pressure relays utilized in trip application • Level Switch (71)

Chapter 2 – Sudden Pressure Relays

Maintenance Intervals and Activities

In order to determine present industry practices related to sudden pressure relay maintenance, the SPCS conducted a survey of Transmission Owners and Generator Owners in all eight Regions requesting information related to their maintenance practices. The SPCS received responses from 75 Transmission Owners and 109 Generator Owners. Note that, for the purpose of the survey, sudden pressure relays included the following: the "sudden pressure relay" (SPR) originally manufactured by Westinghouse, the "rapid pressure rise relay" (RPR) manufactured by Qualitrol, and a variety of Buchholz relays. A copy of the survey is included in Appendix C.

Table 2 provides a summary of the results of the responses:

Table 2: Sudden Pressure Relay Maintenance Practices – Survey Results

	Transmission Owner	Generator Owner
Number of responding owners that trip with Sudden Pressure Relays:	67	84
Percentage of responding owners who trip that have a Maintenance Program:	75%	78%
Percentage of maintenance programs that include testing the pressure actuator:	81%	77%
Average Maintenance interval reported:	5.9 years	4.9 years

Additionally, in order to validate the information noted above, the SPCS contacted the following entities for their feedback: the IEEE Power System Relaying Committee, the IEEE Transformer Committee, the Doble Transformer Committee, the NATF System Protection Practices Group, and the EPRI Generator Owner/Operator Technical Focus Group. All of these organizations indicated the results of the SPCS survey are consistent with their respective experiences.

Pressure Actuator Testing

The pressure actuator can take several forms; however, the basic function is to detect a sudden pressure increase within the transformer that is outside of the normal pressure changes that would occur due to expansion and contraction of the oil as a result of external temperature changes or heating due to loading. These devices can be installed at various locations on the transformer and, depending on location, may require the equipment to be removed from service prior to testing the device.

The SPCS also assessed the maintenance activities included in Table 1-1 of PRC-005-2 and concluded that the activities necessary for sudden pressure relay maintenance and testing are analogous to activities performed during maintenance and testing of electromechanical protective relays identified in Table 1-1: Protective Relay.

Sudden Pressure Control Circuitry

The only control circuitry associated with the sudden pressure relays is the circuit which trips the breaker or other interrupting device. As noted in the Supplementary Reference and FAQ document associated with PRC-005-2, maintenance and testing of this circuitry is already included in the requirements of the revised standard. The SPCS believes activities and intervals for maintenance and testing of sudden pressure control circuitry should be explicitly stated in the associated Table 1-5: Control Circuitry Associated With Protective Functions.

Chapter 3 – Recommendations

Based on its analysis, the SPCS has determined the only device that responds to non-electrical quantities that should be included in PRC-005 is a sudden pressure relay that trips the equipment it is monitoring. Therefore, the SPCS recommends the following guidance for future development of NERC Reliability Standard PRC-005, Protection System Maintenance, to address the concerns stated in FERC Order No. 758.

Modify PRC-005 to explicitly address maintenance and testing of the actuator device of the sudden pressure relay when applied as a protective device that trips a facility described in the applicability section of the Reliability Standard.

- Develop minimum maintenance activities for sudden pressure relays similar to Table 1-1: Protective Relay. Based on the survey results, the SPCS recommends the maximum interval for time-based maintenance programs be 6 years.
- Modify Table 1-5: "Control Circuitry Associated With Protective Functions" to explicitly include the sudden pressure control circuitry.

Appendix A – Attachment to NERC Informational Filing in Response to FERC Order No. 758 – April 12, 2012

ATTACHMENT A

NERC System Protection and Control Subcommittee
Tentative Schedule for Activities Related to
Paragraph 15 of FERC Order No. 758

February 2012 – May 2012	Develop a list of devices to be addressed in a subsequent revision of PRC-005 (use the IEEE device list as a reference of possible devices to be considered) Document devices considered and recommendations for which items are/are not to be included
May 2012 – May 2013	Work with IEEE Power System Relaying Committee and IEEE Transformer Committee regarding minimum maintenance activities and maximum intervals for those devices recommended for inclusion in PRC-005 Review manufacturer's literature and recommended maintenance practices Conduct a survey, possibly through the Transmission Forum, of maintenance practices for identified devices
May 2013 – September 2013	Develop a report to NERC Planning Committee
September 2013 – December 2013	NERC Planning Committee review and approval
First Quarter 2014	Submit technical document(s) to NERC Standards Committee

Prepared by the NERC System Protection and Control Subcommittee

March 15, 2011

Appendix B – IEEE Device Numbers and Functions

The devices in switching equipment are referred to by numbers, according to the functions they perform. These numbers are based on a system which has been adopted as standard for automatic switchgear by IEEE. This system is used on connection diagrams, in instruction books, and in specifications.

1 – Master element

An initiating device, such as a control switch, voltage relay, float switch etc., that serves either directly, or through such permissive devices as protective and time-delay relays, to place an equipment in or out of operation.

2 – Time-delay starting or closing relay

A device that functions to give a desired amount of time delay before or after any point of operation in a switching sequence or protective relay system, except as specifically provided by device functions 48, 62 and 79 described later.

3 – Checking or interlocking relay

A device that operates in response to the position of a number of other devices, (or to a number of predetermined conditions), in an equipment to allow an operating sequence to proceed, to stop, or to provide a check of the position of these devices or of these conditions for any purpose.

4 – Master contactor

A device, generally controlled by device No. 1 or equivalent, and the required permissive and protective devices, that serve to make and break the necessary control circuits to place an equipment into operation under the desired conditions and to take it out of operation under other or abnormal conditions.

5 – Stopping device

A control device used primarily to shut down an equipment and hold it out of operation. [This device may be manually or electrically actuated, but excludes the function of electrical lockout (see device function 86) on abnormal conditions.]

6 – Starting circuit breaker

A device whose principal function is to connect a machine to its source of starting voltage.

7 – Rate-of-rise relay

A relay that functions on an excessive rate of rise of current.

8 – Control power disconnecting device

A disconnecting device, such as a knife switch, circuit breaker, or pull-out fuse block, used for the purpose of respectively connecting and disconnecting the source of control power to and from the control bus or equipment.

9 – Reversing device

A device is used for the purpose of reversing a machine field or for performing any other reversing functions.

10 – Unit sequence switch

A switch used to change the sequence in which units may be placed in and out of service in multiple-unit equipment.

11 – Multifunction device

A device that performs three or more comparatively important functions that could only be designated by combining several of these device function numbers. All of the functions performed by device 11 shall be defined in the drawing legend or device function list.

12 – Over speed device

A device, usually a direct connected speed switch, that functions on machine over speed.

13 – Synchronous-speed device
A device s such as a centrifugal speed switch, a slip frequency relay, a voltage relay, an undercurrent relay, or any other type of device that operates at approximately the synchronous speed of a machine.

14 – Underspeed device
A device that functions when the speed of a machine falls below a pre-determined value.

15 – Speed or frequency matching device
A device that functions to match and hold the speed or the frequency of a machine or of a system equal to, or approximately equal to, that of another machine, source, or system.

16 – Reserved for future application

17 – Shunting or discharge switch
A switch that serves to open or to close a shunting circuit around any piece of apparatus (except a resistor), such as a machine field, a machine armature, a capacitor, or a reactor.

Note: This excludes devices that perform such shunting operations as may be necessary in the process of starting a machine by devices 6 or 42, or their equivalent, and also excludes device 73 function that serves for the switching of resistors.

18 – Accelerating or decelerating device
A deice used to close or to cause the closing of circuits that are used to increase or decrease the speed of a machine.

19 – Starting-to-running transition
A contactor that operates to initiate or cause the automatic transfer of a machine from the starting to the running power connection.

20 – Electrically operated valve
An electrically operated, controlled, or monitored valve used in a fluid, air, gas, or vacuum line.

Note: The function of the valve may be indicated by the use of suffixes.

21 – Distance relay
A relay that functions when the circuit admittance, impedance, or reactance increases or decreases beyond a predetermined value.

22 – Equalizer circuit breaker
A breaker that serves to control or to make and break the equalizer or the current balancing connections for a machine field, or for regulating equipment, in a multiple unit installation.

23 – Temperature control device
A device that functions to raise or to lower the temperature of a machine or other apparatus, or of any medium, when its temperature falls below or rises above a predetermined value.

Note: An example is a thermostat that switches on a space heater in a switchgear assembly when the temperature falls to a desired value as distinguished from a device that is used to provide automatic temperature regulation between close limits and would be designated as 90T.

24 – Volts per hertz relay
A relay that functions when the ratio of voltage to frequency exceeds a preset value. The relay may have an instantaneous or a time characteristic.

25 – Synchronizing or synchronism check
A device that operates when two ac circuits are within the desired limits of frequency, phase angle, or voltage to permit or to cause the paralleling of these two circuits.

26 – Apparatus thermal device
Functions when the temperature of the protected apparatus (other than the load-carrying windings of machines and transformers as covered by device function number 49) or of a liquid or other medium exceeds a predetermined value; or when the temperature of the protected apparatus or of any medium decreases below a predetermined value.

27 – Under voltage relay
A relay that operates when its input voltage is less than a predetermined value.

28 – Flame detector
A device that monitors the presence of the pilot or main flame in such apparatus as a gas turbine or a steam boiler.

29 – Isolating contactor
A device used expressly for disconnecting one circuit from another for the purposes of emergency operation, maintenance, or test.

30 – Annunciator relay
A non-automatically reset device that gives a number of separate visual indications upon the functioning of protective devices and that may also be arranged to perform a lock-out function.

31 – Separate excitation device
A device that connects a circuit, such as the shunt field of a synchronous converter, to a source of separate excitation during the starting sequence; or one which energizes the excitation and ignition circuits of a power rectifier.

32 – Directional power relay
A relay that operates on a predetermined value of power flow in a given direction or upon reverse power flow such as that resulting from the motoring of a generator upon loss of its prime mover.

33 – Position switch
A switch that makes or breaks contact when the main device or piece of apparatus that has no device function number reaches a given position.

34 – Master sequence device
A device such as a motor operated multi contact switch, or the equivalent, or a programming device, such as a computer, that establishes or determines the operating sequence of the major devices in an equipment during starting and stopping or during other sequential switching operations.

35 – Brush-operating or slip-ring short circuiting
A device used for raising, lowering or shifting the brushes of a machine; short-circuiting its slip rings; or engaging or disengaging the contacts of a mechanical rectifier.

36 – Polarity or polarizing voltage device
A device that operates, or permits the operation of, another device on a predetermined polarity only or that verifies the presence of a polarizing voltage in an equipment.

37 – Undercurrent or under power relay
A device that functions when the current or power flow decreases below a predetermined value.

38 – Bearing protective device
A device that functions on excessive bearing temperature or on other abnormal mechanical conditions associated with the bearing, such as undue wear, which may eventually result in excessive bearing temperature or failure.

39- Mechanical condition monitor
A device that functions upon the occurrence of an abnormal mechanical condition (except that associated with bearings as covered under device function 38), such as excessive vibration, eccentricity, expansion, shock, tilting, or seal failure.

40 – Field relay
A relay that functions on a given or abnormally low value or failure of machine field current, or on an excessive value of the reactive component of armature current in an ac machine indicating abnormally low field excitation.

41 – Field circuit breaker
A device that functions to apply or remove the field excitation of a machine.

42 – Running circuit breaker
A device whose principal function is to connect a machine to its source of running or
operating voltage. This function may also be used for a device, such as a contactor, that is used in series with a circuit breaker or other fault protecting means, primarily for frequent opening and closing of the circuit.

43 – Manual transfer or selector device
A manually operated device that transfers the control circuits in order to modify the plan of operation of the switching equipment or of some of the devices.

44 – Unit sequence starting relay
A relay that functions to start the next available unit in multiple unit equipment upon the failure or nonavailability of the normally preceding unit.

45 – Atmospheric condition monitor
A device that functions upon the occurrence of an abnormal atmospheric condition, such as damaging fumes, explosive mixtures, smoke, or fire.

46 – Reverse-phase or phase-balance
A current relay is a relay that functions when the polyphase currents are of reverse phase sequence or when the polyphase currents are unbalanced or contain negative phase-sequence components above a given amount.

47 – Phase-sequence or phase-balance
A voltage relay that functions upon a predetermined value of polyphase voltage in the desired phase sequence, or when the polyphase voltages are unbalanced, or when the negative phase-sequence voltage exceeds a given amount.

48 – Incomplete sequence relay
A relay that generally returns the equipment to the normal, or off, position and locks it out if the normal starting, operating, or stopping sequence is not properly completed within a predetermined time. If the device is used for alarm purposes only, it should preferably be designated as 48A (alarm).

49 – Machine or transformer thermal
A relay that functions when the temperature of a machine armature winding or other load-carrying winding or element of a machine or power transformer exceeds a predetermined value.

50 – Instantaneous over current relay
A relay that functions instantaneously on an excessive value of current.

51 – Ac time over current relay
A relay with either a definite or inverse time characteristic that functions when the ac input current exceeds a predetermined value, and in which the input current and operating time are independently related or inversely related through a substantial portion of the performance range.

52 – Ac circuit breaker
A device that is used to close and interrupt an ac power circuit under normal conditions or to interrupt this circuit under fault or emergency conditions.

53 – Exciter or dc generator relay
A relay that forces the dc machine field excitation to build up during starting or that functions when the machine voltage has built up to a given value.

54 – Turning gear engaging device
An electrically operated, controlled, or monitored device that functions to cause the turning gear to engage (or disengage) the machine shaft.

55 – Power factor relay
A relay that operates when the power factor in an ac circuit rises above or falls below a predetermined value.

56 – Field application relay
A relay that automatically controls the application of the field excitation to an ac motor at some predetermined point in the slip cycle.

57 – Short-circuiting or grounding device
A primary circuit switching device that functions to short circuit or ground a circuit in response to automatic or manual means.

58 – Rectification failure relay
A device that functions if a power rectifier fails to conduct or block properly.

59 – Over voltage relay
A relay that operates when its input voltage is higher than a predetermined value.

60 – Voltage or current balance relay
A relay that operates on a given difference in voltage, or current input or output, of two circuits.

61 – Density switch or sensor
A device that operates on a given value, or a given rate of change, of gas density.

62 – Time-delay stopping or opening relay
A time-delay relay that serves in conjunction with the device that initiates the shutdown, stopping, or opening operation in an automatic sequence or protective relay system.

63 – Pressure switch
A switch that operates on given values, or on a given rate of change, of pressure.

64 – Ground detector relay
A relay that operates upon failure of machine or other apparatus insulation to ground, or on flashover of a dc machine to ground.

Note: This function is assigned only to a relay which detects the flow of current from the frame of a machine or enclosing case or structure of a piece of apparatus to ground, or detects a ground on a normally ungrounded winding or circuit. It is not applied to a device connected in the secondary neutral of a current transformer, or in the secondary neutral of current transformers, connected in the power circuit of a normally grounded system.

65 – Governor
The assembly of fluid, electrical, or mechanical control equipment used for regulating the flow of water, steam, or other media to the prime mover for such purposes as starting, holding speed or load, or stopping.

66 – Notching or jogging device
A device that functions to allow only a specified number of operations of a given device or equipment, or a specified number of successive operations within a given time of each other. It is also a device that functions to energize a circuit

periodically or for fractions of specified time intervals, or that is used to permit intermittent acceleration or jogging of a machine at low speeds for mechanical positioning.

67 – Ac directional over current relay
A relay that functions on a desired value of ac over current flowing in a predetermined direction.

68 – Blocking relay
A relay that initiates a pilot signal for blocking of tripping on external faults in a transmission line or in other apparatus under predetermined conditions, or that cooperates with other devices to block tripping or to block reclosing on an out-of-step condition or on power swings.

69 – Permissive control device
Generally, a two-position device that in one position permits the closing of a circuit
breaker, or the placing of an equipment into operation, and in the other position prevents the circuit breaker or the equipment from being operated.

70 – Rheostat
A variable resistance device used in an electric circuit which is electrically operated or has other electrical accessories, such as auxiliary, position, or limit switches.

71 – Level switch
A switch that operates on given values, or on a given rate of change, of level.

72 – Dc circuit breaker
A circuit breaker used to close and interrupt a dc power circuit under normal conditions or to interrupt this circuit under fault or emergency conditions.

73 – Load-resistor contactor
A contactor used to shunt or insert a step of load limiting, shifting, or indicating resistance in a power circuit, or to switch a space heater in circuit, or to switch a light, or regenerative load resistor of a power rectifier or other machine in and out of circuit.

74 – Alarm relay
A relay other than an annunciator, as covered under device function 30, that is used to operate, or that operates in connection with, a visual or audible alarm.

75 – Position changing mechanism
A mechanism that is used for moving a main device from one position to another in an equipment; for example, shifting a removable circuit breaker unit to and from the connected, disconnected, and test positions.

76 – Dc over current relay
A relay that functions when the current in a dc circuit exceeds a given value.

77 – Telemetering device
A transmitter used to generate and transmit to a remote location an electrical signal representing a measured quantity, or a receiver used to receive the electrical signal from a remote transmitter and convert the signal to represent the original measured quantity.

78 – Phase-angle measuring or out-of step
A relay that functions at a predetermined phase angle between two voltages, or between two currents, or between voltage and current.

79 – Ac reclosing relay
A relay that controls the automatic reclosing and locking out of an ac circuit interrupter.

80 – Flow switch
A switch that operates on given values, or on a given rate of change, of flow.

81 – Frequency relay
A relay that responds to the frequency of an electrical quantity, operating when
the frequency or rate of change of frequency exceeds or is less than a predetermined value.

82 – Dc load-measuring reclosing relay
A relay that controls the automatic closing and reclosing of a dc circuit interrupter, generally in response to load circuit conditions.

83 – Automatic selective control or transfer relay
A relay that operates to select automatically between certain sources or conditions in equipment or that performs a transfer operation automatically.

84 – Operating mechanism
The complete electrical mechanism or servomechanism, including the operating motor, solenoids, position switches, etc., for a tap changer, induction regulator, or any similar piece of apparatus that otherwise has no device function number.

85 – Carrier or pilot-wire receiver relay
A relay that is operated or restrained by a signal used in connection with carrier-current or dc pilot-wire fault directional relaying.

86 – Lockout relay
An electrically operated hand or electrically reset auxiliary relay that is operated upon the occurrence of abnormal conditions to maintain associated equipment or devices out of service until it is reset.

87 – Differential protective relay
A protective relay that functions on a percentage, or phase angle, or other quantitative difference between two currents or some other electrical quantities.

88 – Auxiliary motor or motor generator
A device used for operating auxiliary equipment, such as pumps, blowers, exciters, rotating magnetic amplifiers, etc.

89 – Line switch
Used as a disconnecting, load interrupter, or isolating switch in an ac or dc power circuit. (This device function number is normally not necessary unless the switch is electrically operated or has electrical accessories, such as an auxiliary switch, a magnetic lock, etc.)

90 – Regulating device
Functions to regulate a quantity or quantities, such as voltage, current, power, speed, frequency, temperature, and load, at a certain value or between certain (generally close) limits for machines, tie lines, or other apparatus.

91 – Voltage directional relay
A relay that operates when the voltage across an open circuit breaker or contactor exceeds a given value in a given direction.

92 – Voltage and power directional relay
A relay that permits or causes the connection of two circuits when the voltage difference between them exceeds a given value in a predetermined direction and causes these two circuits to be disconnected from each other when the power flowing between them exceeds a given value in the opposite direction.

93 – Field-changing contactor
Functions to increase or decrease, in one step, the value of field excitation on a machine.

94 – Tripping or trip-free relay

Functions to trip a circuit breaker, contactor, or equipment, or to permit immediate tripping by other devices; or to prevent immediate reclosing of a circuit interrupter if it should open automatically, even though its closing circuit is maintained closed.

95, 96, 97, 98, 99 –

Used only for specific applications on individual installations where none of the assigned numbered functions from 1 to 94 is suitable.

Appendix C – Initial Screening of Devices

Table C-1: Initial Screening of Devices			
Device Number	**Function**	**Categorization per Step 1 – Analysis of Individual Devices**	**Further Analysis**
1	Master Element	Control device	No
2	Time-Delay Starting or Closing Relay	Typically a control device When used in a protection system, an auxiliary relay addressed by the protection system definition and subject to PRC-005 if applied on an applicable facility	No
3	Checking or Interlocking Relay	Control device	No
4	Master Contactor	Control device	No
5	Stopping Device	Control device	No
6	Starting Circuit Breaker	Primary equipment	No
7	Rate-of-rise Relay	Protective relay addressed by the protection system definition and subject to PRC-005 if applied on an applicable facility (generally an integral part of a more complex protective relay)	No
8	Control Power Disconnecting Device	Control device	No
9	Reversing Device	Control device	No
10	Unit Sequence Switch	Control device	No
11	Multifunction Device	Protective relay addressed by the protection system definition and subject to PRC-005 if applied on an applicable facility	No
12	Overspeed Device	Identified for further analysis – see Appendix D	Yes
13	Synchronous-Speed Device	Control device	No
14	Underspeed Device	Identified for further analysis – see Appendix D	Yes
15	Speed or Frequency Matching Device	Control device	No
16	(Reserved For Future Application)	Not applicable	—
17	Shunting or Discharge-Switch	Control device	No
18	Accelerating or Decelerating Device	Control device	No

Table C-1: Initial Screening of Devices			
Device Number	**Function**	**Categorization per Step 1 – Analysis of Individual Devices**	**Further Analysis**
19	Starting-to-Running Transition Contactor	Control device	No
20	Electrically Operated Valve	Primary equipment	No
21	Distance Relay	Protective relay addressed by the protection system definition and subject to PRC-005 if applied on an applicable facility	No
22	Equalizer Circuit Breaker	Control device	No
23	Temperature Control Device	Control device	No
24	Volts-per-Hertz Relay	Protective relay addressed by the protection system definition and subject to PRC-005 if applied on an applicable facility	No
25	Synchronizing or Synchronism Check	Subject of separate report by SAMS and SPCS	No
26	Apparatus Thermal Device	Identified for further analysis – see Appendix D	Yes
27	Undervoltage Relay	Protective relay addressed by the protection system definition and subject to PRC-005 if applied on an applicable facility	No
28	Flame Detector	Identified for further analysis – see Appendix D	Yes
29	Isolating Contactor	Control device	No
30	Annunciator Relay	Generally provides information that is advisory in nature When used in a protection system, an auxiliary relay addressed by the protection system definition and subject to PRC-005 if applied on an applicable facility	No
31	Separate Excitation Device	Control device	No
32	Directional Power Relay	Protective relay addressed by the protection system definition and subject to PRC-005 if applied on an applicable facility	No
33	Position Switch	Control device	No
34	Master Sequence Device	Control device	No
35	Brush-Operating or Slip-Ring Short-Circuiting Device	Control device	No
36	Polarity or Polarizing Voltage Device	Control device	No
37	Undercurrent or Underpower Relay	Protective relay addressed by the protection system definition and subject to PRC-005 if applied on an applicable facility	No
38	Bearing Protective Device	Identified for further analysis – see Appendix D	Yes

Table C-1: Initial Screening of Devices			
Device Number	**Function**	**Categorization per Step 1 – Analysis of Individual Devices**	**Further Analysis**
39	Mechanical Condition Monitor	Identified for further analysis – see Appendix D	Yes
40	Field Relay	Protective relay addressed by the protection system definition and subject to PRC-005 if applied on an applicable facility	No
41	Field Circuit Breaker	Primary equipment	No
42	Running Circuit Breaker	Primary Equipment	No
43	Manual Transfer or Selector Device	Control device	No
44	Unit Sequence Starting Relay	Control device	No
45	Atmospheric Condition Monitor	Identified for further analysis – see Appendix D	Yes
46	Reverse-Phase or Phase-Balance Current Relay	Protective relay addressed by the protection system definition and subject to PRC-005 if applied on an applicable facility	No
47	Phase-Sequence or Phase Balance Voltage Relay	Protective relay addressed by the protection system definition and subject to PRC-005 if applied on an applicable facility	No
48	Incomplete Sequence Relay	Control device	No
49	Machine or Transformer Thermal Relay	Identified for further analysis – see Appendix D	Yes
50	Instantaneous Overcurrent	Protective relay addressed by the protection system definition and subject to PRC-005 if applied on an applicable facility	No
51	AC Time Overcurrent Relay	Protective relay addressed by the protection system definition and subject to PRC-005 if applied on an applicable facility	No
52	AC Circuit Breaker	Primary Equipment	No
53	Exciter or DC Generator Relay	Control device	No
54	Turning Gear Engaging Device	Control device	No
55	Power-Factor Relay	Control device	No
56	Field Application Relay	Control device	No
57	Short-Circuiting or Grounding Device	Primary equipment	No
58	Rectification Failure Relay	Protective relay addressed by the protection system definition and subject to PRC-005 if applied on an applicable facility	No

Table C-1: Initial Screening of Devices			
Device Number	**Function**	**Categorization per Step 1 – Analysis of Individual Devices**	**Further Analysis**
59	Overvoltage Relay	Protective relay addressed by the protection system definition and subject to PRC-005 if applied on an applicable facility	No
60	Voltage or Current Balance Relay	Protective relay addressed by the protection system definition and subject to PRC-005 if applied on an applicable facility	No
61	Density Switch or Sensor	Identified for further analysis – see Appendix D	Yes
62	Time-delay Stopping or Opening Relay	Auxiliary relay addressed by the protection system definition and subject to PRC-005 if applied on an applicable facility	No
63	Pressure Switch	Identified for further analysis – see Appendix D	Yes
64	Ground Detector Relay	Protective relay addressed by the protection system definition and subject to PRC-005 if applied on an applicable facility	No
65	Governor	Control device	No
66	Notching or Jogging Device	Control device	No
67	AC Directional Overcurrent Relay	Protective relay addressed by the protection system definition and subject to PRC-005 if applied on an applicable facility	No
68	Blocking Relay	Protective relay addressed by the protection system definition and subject to PRC-005 if applied on an applicable facility	No
69	Permissive Control Device	Control device	No
70	Rheostat	Control device	No
71	Level Switch	Identified for further analysis – see Appendix D	Yes
72	DC Circuit Breaker	Primary equipment	No
73	Load-Resistor Contactor	Control device	No
74	Alarm Relay	Provides information that is advisory in nature	No
75	Position-Changing Mechanism	Control device	No
76	DC Overcurrent Relay	Protective relay addressed by the protection system definition and subject to PRC-005 if applied on an applicable facility	No
77	Telemetering Device	Control device	No
78	Phase-Angle Measuring or Out-Of-Step Protective Relay	Protective relay addressed by the protection system definition and subject to PRC-005 if applied on an applicable facility	No
79	AC Reclosing Relay	Subject of separate report by SAMS and SPCS	No
80	Flow Switch	Control device	No

Table C-1: Initial Screening of Devices			
Device Number	**Function**	**Categorization per Step 1 – Analysis of Individual Devices**	**Further Analysis**
81	Frequency Relay	Protective relay addressed by the protection system definition and subject to PRC-005 if applied on an applicable facility	No
82	DC Load-Measuring Reclosing Relay	Protective relay addressed by the protection system definition and subject to PRC-005 if applied on an applicable facility	No
83	Automatic Selective Control or Transfer Relay	Control device	No
84	Operating Mechanism	Control device	No
85	Carrier or Pilot-Wire Receiver Relay	Protective relay addressed by the protection system definition and subject to PRC-005 if applied on an applicable facility	No
86	Lockout Relay	Auxiliary relay addressed by the protection system definition and subject to PRC-005 if applied on an applicable facility	No
87	Differential Protective Relay	Protective relay addressed by the protection system definition and subject to PRC-005 if applied on an applicable facility	No
88	Auxiliary Motor or Motor Generator	Primary equipment	No
89	Line Switch	Primary equipment	No
90	Regulating Device	Control device	No
91	Voltage Directional Relay	Protective relay addressed by the protection system definition and subject to PRC-005 if applied on an applicable facility	No
92	Voltage And Power Directional Relay	Protective relay addressed by the protection system definition and subject to PRC-005 if applied on an applicable facility	No
93	Field-Changing Contactor	Control device	No
94	Tripping or Trip-Free Relay	Auxiliary relay addressed by the protection system definition and subject to PRC-005 if applied on an applicable facility	No
95	(Reserved For Special Application)	Not applicable	—
96	(Reserved For Special Application)	Not applicable	—
97	(Reserved For Special Application)	Not applicable	—
98	(Reserved For Special Application)	Not applicable	—
99	(Reserved For Special Application)	Not applicable	—

Appendix D – Detailed Assessment of Devices

The SPCS reviewed a list of all IEEE/ANSI device numbers and discussed each device type. After eliminating devices already addressed by the revised definition of Protection System and devices that are clearly not protective devices, such as primary equipment and control devices, detailed analysis was performed for the following list of devices:

- Overspeed Device (12)
- Underspeed Device (14)
- Apparatus Thermal Device (26)
- Flame Detector (28)
- Bearing Protective Device (38)
- Mechanical Condition Monitor (39)
- Atmospheric Condition Monitor (45)
- Machine or Transformer Thermal Relay (49)
- Density Switch or Sensor (61)
- Pressure Switch (63)
- Level Switch (71)

For each device, a summary of the evaluation and conclusion is presented. As a result of this analysis, the SPCS concludes that the only devices responding to non-electrical quantities that should be included in the applicability of PRC-005 are sudden pressure relays utilized in a tripping function. When applied in a tripping function, these devices initiate actions to clear faults to support reliable operation of the Bulk-Power System. The other devices evaluated respond to abnormal equipment conditions and take action to protect equipment from mechanical or thermal damage or premature loss of life, rather than for the purpose of initiating fault clearing or mitigating an abnormal system condition to support reliable operation of the Bulk-Power System. Thus, these devices are not recommended for inclusion in PRC-005. The SPCS recognizes that devices that respond to abnormal equipment conditions perform an important function. However, these devices do not directly support NERC's mission to ensure the reliability of the Bulk-Power System.

Overspeed (12): Usually a direct-connected speed switch that functions on machine over speed.

Action taken: This device provides an alarm, and in some cases trips the affected equipment, in response to the equipment operating at an excessive speed. This device is set to operate after an electrical device responding to frequency, which is set at a lower threshold.

Impact of inadvertent operation: Inadvertent operation would result in a nuisance alarm, unnecessary control action, or unnecessarily removing the equipment from service. In some cases, the device is applied to primary equipment, while in other cases, it may be applied to ancillary equipment such as a fan or motor. The impact of removing BES equipment from service would be the same as for a TPL-002-0b Category B contingency, "Loss of an Element without a Fault," for which the system is designed and operated to withstand.

Impact of failure to operate: Overspeed protection responds to an abnormal operating condition rather than a fault and, for generator applications, typically is not expected to operate when the generator is connected to the system, thereby limiting the potential impact to the Bulk-Power System. A failure to operate could result in damage to the generator prime mover depending on what other protection or controls operate to remove the unit from service, but would not result in removal of other elements from service.

Risk of inadvertent operation during a disturbance: The overspeed device directly measures the speed of the machine. Therefore, an overspeed device should only operate during a fault or abnormal system condition if an actual overspeed condition occurs (e.g., due to a loss of synchronism) or if an independent failure of the device occurs. There is no operating experience in which misoperation of an overspeed device in response to a system disturbance has contributed to a cascading event.

Conclusion: This device responds to an abnormal equipment condition and takes action to protect the equipment from mechanical damage rather than for the purpose of initiating fault clearing or mitigating an abnormal system condition to support reliable operation of the Bulk-Power System.

Underspeed (14): A device that functions when the speed of a machine falls below a pre-determined value.

Action taken: This device provides an alarm, and in some cases trips the affected equipment, in response to the equipment operating at insufficient speed. This device is set to operate after an electrical device responding to frequency, which is set at a higher threshold.

Impact of inadvertent operation: Inadvertent operation would result in a nuisance alarm, unnecessary control action, or unnecessarily removing the equipment from service. In some cases, the device is applied to primary equipment, while in other cases, it may be applied to ancillary equipment such as a fan or motor. The impact of removing BES equipment from service would be the same as for a TPL-002-0b Category B contingency, “Loss of an Element without a Fault,” for which the system is designed and operated to withstand.

Impact of failure to operate: Underspeed protection responds to an abnormal operating condition rather than a fault. A failure to operate could result in damage to the generator prime mover depending on what other protection or controls operate to remove the unit from service, but would not result in removal of other elements from service.

Risk of inadvertent operation during a disturbance: The underspeed device directly measures the speed of the machine. Therefore, an underspeed device should only operate during a fault or abnormal system condition if an actual underspeed condition occurs (e.g., due to a loss of synchronism) or if an independent failure of the device occurs. There is no operating experience in which misoperation of an underspeed device in response to a system disturbance has contributed to a cascading event.

Conclusion: This device responds to an abnormal equipment condition and takes action to protect the equipment from mechanical damage rather than for the purpose of initiating fault clearing or mitigating an abnormal system condition to support reliable operation of the Bulk-Power System.

Apparatus thermal device (26): Functions when the temperature of the protected apparatus (other than the load-carrying windings of machines and transformers as covered by device function number 49) or of a liquid or other medium (e.g., transformer top oil temperature, which may be the most prevalent) exceeds a predetermined value; or when the temperature of the protected apparatus or of any medium decreases below a predetermined value.

Action taken: This device provides an alarm, and in some cases trips the affected equipment, in response to the equipment operating at an elevated temperature that may result in increased loss of life.

Impact of inadvertent operation: Inadvertent operation would result in a nuisance alarm or unnecessarily removing the equipment from service. The impact of removing the equipment from service would be the same as for a TPL-002-0b Category B contingency, “Loss of an Element without a Fault,” for which the system is designed and operated to withstand.

Impact of failure to operate: Failure to alarm or trip the equipment could lead to loss of life or equipment damage resulting from operation at elevated temperature.

Risk of inadvertent operation during a disturbance: The apparatus thermal device directly measures the temperature of the of the protected apparatus or medium. Therefore, an apparatus thermal device should only operate during a fault or abnormal system condition if the actual temperature is outside its operating limits or if an independent failure of the device occurs. There is no operating experience in which misoperation of an apparatus thermal device in response to a system disturbance has contributed to a cascading event.

Conclusion: This device responds to an abnormal equipment condition and takes action to protect the equipment from excessive loss of life rather than for the purpose of initiating fault clearing or mitigating an abnormal system condition to support reliable operation of the Bulk-Power System.

Flame detector (28): A device that monitors the presence of the pilot or main flame in such apparatus as a gas turbine or a steam boiler.

Action taken: This device initiates a control action to remove the fuel source from a gas turbine or steam turbine boiler in response to a loss of combustion.

Impact of inadvertent operation: Inadvertent operation would result in a nuisance alarm or unnecessarily removing the equipment from service. The impact of removing the equipment from service would be the same as for a TPL-002-0b Category B contingency, “Loss of an Element without a Fault,” for which the system is designed and operated to withstand.

Impact of failure to operate: The flame detector responds to an abnormal operating condition rather than a fault. A failure to operate could result in an uncontrolled delivery of fuel that is not consumed, but would not result in removal of other elements from service.

Risk of inadvertent operation during a disturbance: The flame detector indirectly measures the presence of a flame; however, this is done by monitoring heat or radiation from the flame, which are both independent of power system conditions. Therefore, a flame detector should only operate during a fault or abnormal system condition for an actual loss of flame (e.g., flameout in a combustion turbine) or if an independent failure of the device occurs. There is no operating experience in which misoperation of a flame detector in response to a system disturbance has contributed to a cascading event.

Conclusion: This device responds to an abnormal equipment condition and takes action to protect the equipment from mechanical damage rather than for the purpose of initiating fault clearing or mitigating an abnormal system condition to support reliable operation of the Bulk-Power System.

Bearing protective device (38): Functions on excessive bearing temperature or on other abnormal mechanical conditions associated with the bearing, such as undue wear, which may eventually result in excessive bearing temperature or failure.

Action taken: This device provides an alarm, and in some cases trips the affected equipment, in response to an abnormal condition such as the bearing operating at an elevated temperature. The device typically alarms at one level. When tripping is provided, such as for a hydraulic unit thrust bearing, it trips at a second level.

Impact of inadvertent operation: Inadvertent operation would result in a nuisance alarm or unnecessarily removing the equipment from service. The impact of removing the equipment from service would be the same as for a TPL-002-0b Category B contingency, “Loss of an Element without a Fault,” for which the system is designed and operated to withstand.

Impact of failure to operate: Failure to alarm or trip the equipment could lead to loss of life or excessive wear, and may eventually lead to failure of the bearing.

Risk of inadvertent operation during a disturbance: The bearing protective device indirectly measures the temperature or other physical condition of the bearing; however, this is done by monitoring mechanical quantities in proximity to the bearing which are independent of power system conditions. Therefore, a bearing protective device should only operate during a fault or abnormal system condition for an actual bearing problem or if an independent failure of the device occurs. There is no operating experience in which misoperation of a bearing protective device in response to a system disturbance has contributed to a cascading event.

Conclusion: This device responds to an abnormal equipment condition and takes action to protect the equipment from excessive loss of life or eventual failure rather than for the purpose of initiating fault clearing or mitigating an abnormal system condition to support reliable operation of the Bulk-Power System.

Mechanical condition monitor (39): A device that functions upon the occurrence of an abnormal mechanical condition (except that associated with bearings as covered under device function 38), such as excessive vibration, eccentricity, expansion, shock, tilting, or seal failure.

Action taken: This device provides an alarm, and in some cases trips the affected equipment, in response to an abnormal mechanical condition of the equipment. The device typically alarms at one level, and either provides a second alarm or trips at a second level.

Impact of inadvertent operation: Inadvertent operation would result in a nuisance alarm or unnecessarily removing the equipment from service. The impact of removing the equipment from service would be the same as for a TPL-002-0b Category B contingency, "Loss of an Element without a Fault," for which the system is designed and operated to withstand.

Impact of failure to operate: Failure to alarm or trip the equipment could lead to loss of life or equipment damage.

Risk of inadvertent operation during a disturbance: The mechanical condition monitor indirectly measures the physical condition of the protected device; however, this is done by monitoring mechanical quantities in proximity to the device which are independent of power system conditions. Therefore, a mechanical condition monitor should only operate during a fault or abnormal system condition for an actual mechanical problem or if an independent failure of the device occurs. There is no operating experience in which misoperation of a mechanical condition in response to a system disturbance has contributed to a cascading event.

Conclusion: This device responds to an abnormal equipment condition and takes action to protect the equipment from excessive loss of life or eventual failure rather than for the purpose of initiating fault clearing or mitigating an abnormal system condition to support reliable operation of the Bulk-Power System.

Atmospheric condition monitor (45): A device that functions upon the occurrence of an abnormal atmospheric condition, such as damaging fumes, explosive mixtures, smoke, or fire.

Action taken: This device provides an alarm or shuts down a process and prevents restarting until normal atmospheric conditions are restored.

Impact of inadvertent operation: Inadvertent operation would result in a nuisance alarm or unnecessarily shutting down a process. When shutting down a process results in removing equipment from service, the impact would be the same as for a TPL-002-0b Category B contingency, "Loss of an Element without a Fault," for which the system is designed and operated to withstand.

Impact of failure to operate: Failure to alarm or trip the equipment could lead to an unsafe operating condition and the potential for equipment damage.

Risk of inadvertent operation during a disturbance: The atmospheric condition monitor directly or indirectly measures atmospheric conditions; however, even indirect measurement is accomplished by monitoring atmospheric conditions local to the equipment. Therefore, an atmospheric condition monitor should only operate during a fault or abnormal system condition if the power system event affected atmospheric conditions, or if an independent failure of the monitor occurs. There is no operating experience in which misoperation of an atmospheric condition monitor in response to a system disturbance has contributed to a cascading event.

Conclusion: This device responds to an abnormal equipment condition and takes action to protect the equipment from excessive loss of life rather than for the purpose of initiating fault clearing or mitigating an abnormal system condition to support reliable operation of the Bulk-Power System.

Machine or transformer thermal relay (49): A relay that functions when the temperature of a machine armature winding or other load-carrying winding or element of a machine or power transformer exceeds a predetermined value.

Action taken: This device provides an alarm, and in some cases trips the affected equipment, in response to the equipment operating at an elevated temperature that may result in increased loss of life.

Impact of inadvertent operation: Inadvertent operation would result in a nuisance alarm or unnecessarily removing the equipment from service. The impact of removing the equipment from service would be the same as for a TPL-002-0b Category B contingency, "Loss of an Element without a Fault," for which the system is designed and operated to withstand.

Impact of failure to operate: Failure to alarm or trip the equipment could lead to loss of life resulting from operation at elevated temperature.

Risk of inadvertent operation during a disturbance: The machine or transformer thermal relay indirectly measures the temperature of the of the winding; however, this is accomplished by measuring the temperature of the medium in which the winding is contained. Therefore, a thermal relay should only operate during a fault or abnormal system condition if the calculated temperature is outside its operating limits or if an independent failure of the relay occurs. There is no operating experience in which misoperation of a thermal relay in response to a system disturbance has contributed to a cascading event.

Conclusion: This device responds to an abnormal equipment condition and takes action to protect the equipment from excessive loss of life rather than for the purpose of initiating fault clearing or mitigating an abnormal system condition to support reliable operation of the Bulk-Power System.

Density switch or sensor (61)[5]: A device that operates on a given value, or a given rate of change, of gas density.

Action taken: This device activates a visual indicator and/or switch to provide an alarm in response to a change in gas density within the equipment it is monitoring. In some cases, activation of a switch associated with this device, trips, or blocks tripping of, the affected equipment.

Impact of inadvertent operation: Inadvertent operation would result in a nuisance alarm or unnecessarily removing the equipment from service. The impact of removing the equipment from service would be the same as for a TPL-002-0b Category B contingency, "Loss of an Element without a Fault," for which the system is designed and operated to withstand.

Impact of failure to operate: Failure to alarm, trip, or lockout the equipment could lead to loss of life resulting from operation at low gas density levels.

Risk of inadvertent operation during a disturbance: The density switch or sensor may directly or indirectly measure gas density; however, even indirect measurement is accomplished by measuring both pressure and temperature of the gas. Therefore, a density switch or sensor should only operate during a fault or abnormal system condition if the gas density is outside its operating limits or if an independent failure of the switch or sensor occurs. There is no operating experience in which misoperation of a density switch or sensor in response to a system disturbance has contributed to a cascading event.

[5] Gas density is affected by changes in pressure and temperature. Gas density monitors are modified pressure measuring instruments with electrical accessories. Gas density monitors typically combine both measuring and switching functions in one single instrument. Because gas density is strongly affected by changes in pressure, the switching functions provided with a gas density monitor are often labeled "63" rather than "61".

Conclusion: This device responds to an abnormal equipment condition and takes action to protect the equipment from excessive loss of life rather than for the purpose of initiating fault clearing or mitigating an abnormal system condition to support reliable operation of the Bulk-Power System.

Pressure switch (63): A switch that operates on given values, or on a given rate of change, of pressure.

Action taken: This device provides an alarm, and in some cases trips the affected equipment, in response to changes in pressure within a device such as a circuit breaker or transformer.

Impact of inadvertent operation: Inadvertent operation would result in a nuisance alarm or unnecessarily removing the equipment from service. The impact of removing the equipment from service would be the same as for a TPL-002-0b Category B contingency, "Loss of an Element without a Fault," for which the system is designed and operated to withstand.

Impact of failure to operate: Failure to alarm or trip the equipment could lead to unavailability of the equipment, loss of life resulting from operation at low pressure, or extended exposure to fault current.

Risk of inadvertent operation during a disturbance: The pressure switch directly measures pressure of the monitored medium. A pressure switch should only operate during a fault or abnormal system condition if a pressure exceeds the level necessary to operate the device. In some applications, such as transformer sudden pressure relays used to detect faults internal to a transformer, the pressure switch may operate due to a pressure change associated with through-fault current caused by an external fault. There is no operating experience in which misoperation of a pressure switch in response to a system disturbance has contributed to a cascading event; however, inadvertent operation for an external fault could result in tripping additional system elements.

Conclusion: This device responds to an abnormal equipment condition, such as low gas or air pressure, as well as rapid pressure rises associated with faults in oil-filled equipment (e.g., transformers and shunt reactors). Where this device is applied to respond to abnormal equipment conditions, it takes action to protect the equipment from excessive loss of life or to indicate unavailability of service, rather than for the purpose of initiating fault clearing or mitigating an abnormal system condition to support reliable operation of the Bulk-Power System. Where the device is installed to respond to rapid pressure rise in facilities described in the applicability section of Reliability Standard PRC-005, and configured to take action to initiate fault clearing to support reliable operation of the Bulk-Power System, it should be included as a device to be maintained and tested.

Level switch (71): A switch that operates on given values, or on a given rate of change, of level.

Action taken: This device provides an alarm, and in some cases trips the affected equipment, in response to changes in level within the equipment it is monitoring.

Impact of inadvertent operation: Inadvertent operation would result in a nuisance alarm or unnecessarily removing the equipment from service. The impact of removing the equipment from service would be the same as for a TPL-002-0b Category B contingency, "Loss of an Element without a Fault," for which the system is designed and operated to withstand.

Impact of failure to operate: Failure to alarm, or trip the equipment could lead to loss of life resulting from operation at undesirable levels.

Risk of inadvertent operation during a disturbance: The level switch directly measures liquid level in a device. Therefore, a level switch should only operate during a fault or abnormal system condition if the level is outside its operating limits or if an independent failure of the switch occurs. There is no operating experience in which misoperation of a level switch in response to a system disturbance has contributed to a cascading event.

Conclusion: This device responds to an abnormal equipment condition and takes action to protect the equipment from excessive loss of life rather than for the purpose of initiating fault clearing or mitigating an abnormal system condition to support reliable operation of the Bulk-Power System.

Appendix E – SPCS Sudden Pressure Relay Survey

NERC System Protection and Control Subcommittee (SPCS)

Questionnaire on Maintenance Practices for Fault Pressure Relays
(Sudden Pressure, Rapid Pressure Rise, Buchholz, etc)

Purpose: The SPCS is seeking industry input concerning present industry practices related to the maintenance and testing of Fault Pressure Relays (relays which operate on pressure changes caused by faults) applied on Transmission equipment. This survey pertains specifically to three types of relays:

- Sudden Pressure Relay (SPR)- these devices are mounted on the outside of the transformer and operate on an increase in gas pressure.
- Rapid Pressure Rise Relay (RPR)- these devices are mounted on the outside of the transformer and operate on an increase in oil pressure.
- Buchholz relays- these devices are mounted on some oil-filled power transformers and reactors, equipped with an external overhead oil reservoir called a conservator and detect when oil flows rapidly into the conservator.

Company Name: ____

Survey response from: Transmission _____ Generation _____ Both _____

Note: If practices are different for Transmission and Generation, please provide separate responses

1. Does your company utilize Fault Pressure Relays in the 'trip' application?
   SPR Yes_____ No _____
   RPR Yes_____ No _____
   Buchholz Yes_____ No _____

2. Does your company have a 'maintenance' program in place for these devices?
   SPR Yes _____ No _____
   RPR Yes _____ No _____
   Buchholz Yes_____ No _____
3. Does your company's 'maintenance' program include verifying the trip circuit associated with the Fault Pressure Relay?
   Yes____ No ____ N/A _____ If Yes, what is the prescribed or expected interval. ________

4. Does your company's 'maintenance' program include verifying the operation of the 'pressure actuation' portion of the Sudden Pressure Relay?
   SPR Yes______ No _____ If Yes, prescribed or expected interval? ______
   RPR Yes______ No _____ If Yes, prescribed or expected interval? ______
   Buchholz Yes_____ No _____ If Yes, prescribed or expected interval? ______

   If Yes, does your company simulate an 'operate' and a 'non-operate' condition with some form of pressure test? Yes______ No ____

5. Are there any other activities that are included in the maintenance of Sudden Pressure Relays?
   Yes____ No _____ If so, please describe:

6. Does your company use another type of Fault Pressure Relay not listed above? Yes ____ No _____
   If so, please describe:

Appendix F – System Protection and Control Subcommittee

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Exelon Corporation

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Southern Company

Michael Putt
RE – FRCC
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138 FERC ¶ 61,094
UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

18 CFR Part 40

[Docket No. RM10-5-000; Order No. 758]

Interpretation of Protection System Reliability Standard

(Issued February 3, 2012)

AGENCY: Federal Energy Regulatory Commission

ACTION: Final Rule

SUMMARY: On November 17, 2009, the North American Electric Reliability Corporation (NERC) submitted a petition (Petition) requesting approval of NERC's interpretation of Requirement R1 of Commission-approved Reliability Standard PRC-005-1 (Transmission and Generation Protection System Maintenance and Testing). On December 16, 2010, the Commission issued a Notice of Proposed Rulemaking (NOPR). in the NOPR, the Commission proposed to accept the NERC proposed interpretation of Requirement R1 of Reliability Standard PRC-005-1, and proposed to direct NERC to develop modifications to the PRC-005-1 Reliability Standard through its Reliability Standards development process to address gaps in the Protection System maintenance and testing standard that were highlighted by the proposed interpretation. As a result of the comments received in response to the NOPR, in this order the Commission adopts the NOPR proposal to accept NERC's proposed interpretation. In addition, as discussed below, the Commission accepts, in part, NERC's commitment to address the concerns in the Protection System maintenance and testing standard that were identified by the NOPR

within the Reliability Standards development process, and directs, in part, that the concerns identified by the NOPR with regard to reclosing relays be addressed within the reinitiated PRC-005 revisions.

EFFECTIVE DATE: This rule will become effective 30 days after publication in the FEDERAL REGISTER.

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UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Before Commissioners: Jon Wellinghoff, Chairman;
Philip D. Moeller, John R. Norris,
and Cheryl A. LaFleur.

Interpretation of Protection System Reliability Standard Docket No. RM10-5-000

ORDER NO. 758

FINAL RULE

(Issued February 3, 2012)

1. On November 17, 2009, NERC submitted the Petition requesting approval of NERC's interpretation of Requirement R1 of Commission-approved Reliability Standard PRC-005-1 (Transmission and Generation Protection System Maintenance and Testing). NERC developed the interpretation in response to a request for interpretation submitted to NERC by the Regional Entities Compliance Monitoring Processes Working Group (Working Group).[1] In a December 16, 2010 Notice of Proposed Rulemaking (NOPR),[2] the Commission proposed to accept the NERC proposed interpretation of Requirement R1 of Reliability Standard PRC-005-1, and proposed to direct NERC to develop modifications to the PRC-005-1 Reliability Standard through its Reliability Standards

[1] The Working Group is a subcommittee of the Regional Entity Management Group which consists of the executive management of the eight Regional Entities.

[2] *Interpretation of Protection System Reliability Standard*, Notice of Proposed Rule Making, 75 FR 81,152 (Dec. 27, 2010), FERC Stats. & Regs. ¶ 32,669 (2010).

development process to address gaps in the Protection System maintenance and testing standard highlighted by the proposed interpretation. As a result of the comments received in response to the NOPR, in this order the Commission adopts the NOPR proposal to accept NERC's proposed interpretation. In addition, the Commission accepts, in part, NERC's commitments to address the concerns in the Protection System maintenance and testing standard that were identified by the NOPR within the Reliability Standards development process, and directs, in part, that the concerns identified by the NOPR with regard to reclosing relays be addressed within the reinitiated PRC-005 revisions.

I. Background

2. Section 215 of the Federal Power Act (FPA) requires a Commission-certified Electric Reliability Organization (ERO) to develop mandatory and enforceable Reliability Standards, which are subject to Commission review and approval.[3] Specifically, the Commission may approve, by rule or order, a proposed Reliability Standard or modification to a Reliability Standard if it determines that the Standard is just, reasonable, not unduly discriminatory or preferential, and in the public interest.[4]

[3] 16 U.S.C. 824 (2006).

[4] *Id.* 824o(d)(2).

Once approved, the Reliability Standards may be enforced by the ERO, subject to Commission oversight, or by the Commission independently.[5]

3. Pursuant to section 215 of the FPA, the Commission established a process to select and certify an ERO,[6] and subsequently certified NERC.[7] On April 4, 2006, NERC submitted to the Commission a petition seeking approval of 107 proposed Reliability Standards. On March 16, 2007, the Commission issued a Final Rule, Order No. 693,[8] approving 83 of the 107 Reliability Standards, including Reliability Standard PRC-005-1. In addition, pursuant to section 215(d)(5) of the FPA,[9] the Commission directed NERC to develop modifications to 56 of the 83 approved Reliability Standards, including PRC-005-0.[10]

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[5] Id. 824o(e)(3).

[6] *Rules Concerning Certification of the Electric Reliability Organization; and Procedures for the Establishment, Approval, and Enforcement of Electric Reliability Standards*, Order No. 672, FERC Stats. & Regs. ¶ 31,204, *order on reh'g*, Order No. 672-A, FERC Stats. & Regs. ¶ 31,212 (2006).

[7] *North American Electric Reliability Corp.*, 116 FERC ¶ 61,062, *order on reh'g & compliance*, 117 FERC ¶ 61,126 (2006), *aff'd sub nom. Alcoa, Inc. v. FERC*, 564 F.3d 1342 (D.C. Cir. 2009).

[8] *Mandatory Reliability Standards for the Bulk-Power System*, Order No. 693, FERC Stats. & Regs. ¶ 31,242, *order on reh'g*, Order No. 693-A, 120 FERC ¶ 61,053 (2007).

[9] 16 U.S.C. 824o(d)(5).

[10] Order No. 693, FERC Stats. & Regs. ¶ 31,242 at P 1475.

4. NERC's Rules of Procedure provide that a person that is "directly and materially affected" by Bulk-Power System reliability may request an interpretation of a Reliability Standard.[11] In response, the ERO will assemble a team with relevant expertise to address the requested interpretation and also form a ballot pool. NERC's Rules of Procedure provide that, within 45 days, the team will draft an interpretation of the Reliability Standard and submit it to the ballot pool. If approved by the ballot pool and subsequently by the NERC Board of Trustees (Board), the interpretation is appended to the Reliability Standard and filed with the applicable regulatory authorities for approval.

II. Reliability Standard PRC-005-1

5. The purpose of PRC-005-1 is to "ensure all transmission and generation Protection Systems affecting the reliability of the Bulk Electric System (BES) are maintained and tested." In particular, Requirement R1, requires that:

R1. Each Transmission Owner and any Distribution Provider that owns a transmission Protection System and each Generator Owner that owns a generation Protection System shall have a Protection System maintenance and testing program for Protection Systems that affect the reliability of the BES. The program shall include:

R1.1. Maintenance and testing intervals and their basis.

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[11] NERC Rules of Procedure, Appendix 3A, Reliability Standards Development Procedure, Version 6.1, at 26-27 (2007).

R1.2. Summary of maintenance and testing procedures.

6. NERC currently defines "Protection System" as follows: "Protective relays, associated communication systems, voltage and current sensing devices, station batteries and DC control circuitry."[12]

III. <u>NERC Proposed Interpretation</u>

7. In the NERC Petition, NERC explains that it received a request from the Working Group for an interpretation of Reliability Standard PRC-005-1, Requirement R1, addressing five specific questions. Specifically, the Working Group questions and NERC proposed interpretations include:

Request 1: "Does R1 require a maintenance and testing program for the battery chargers for the 'station batteries' that are considered part of the Protection System?"

Response: "While battery chargers are vital for ensuring 'station batteries' are available to support Protection System functions, they are not identified within the definition of

[12] In Docket No. RD11-13-000, NERC has proposed to revise the definition of Protection System effective on the first day of the first calendar quarter twelve months from approval. The Commission is approving this revision in an order issued concurrently with this order. *See North American Electric Reliability Corp.*, 138 FERC ¶ 61,095 (2012).

'Protection Systems.' Therefore, PRC-005-1 does not currently require maintenance and testing of battery chargers."[13]

Request 2: "Does R1 require a maintenance and testing program for auxiliary relays and sensing devices? If so, what types of auxiliary relays and sensing devices? (i.e., transformer sudden pressure relays)."

Response: "The existing definition of 'Protection System' does not include auxiliary relays; therefore, maintenance and testing of such devices is not explicitly required. Maintenance and testing of such devices is addressed to the degree that an entity's maintenance and testing program for DC control circuits involves maintenance and testing of imbedded auxiliary relays. Maintenance and testing of devices that respond to quantities other than electrical quantities (for example, sudden pressure relays) are not included within Requirement R1."

Request 3: "Does R1 require maintenance and testing of transmission line re-closing relays?"

Response: "No. 'Protective Relays' refer to devices that detect and take action for

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[13] The revised definition of Protection System accepted in Docket No. RD11-13-000 includes battery chargers as an element of the Protection System and, as a result of that change, battery chargers must be maintained and tested. Thus, the modified definition of Protection System approved in Docket No. RD11-13-000, when effective, shall supersede the interpretation of Requirement R1 of Reliability Standard PRC-005-1 approved in this order.

abnormal conditions. Automatic restoration of transmission lines is not a ‘protective’ function.”

Request 4: “Does R1 require a maintenance and testing program for the DC circuitry that is just the circuitry with relays and devices that control actions on breakers, etc., or does R1 require a program for the entire circuit from the battery charger to the relays to circuit breakers and all associated wiring?”

Response: “PRC-005-1 requires that entities 1) address DC control circuitry within their program, 2) have a basis for the way they address this item, and 3) execute the program. Specific additional requirements relative to the scope and/or methods are not established.”

Request 5: “For R1, what are examples of ‘associated communications systems’ that are part of ‘Protection Systems’ that require a maintenance and testing program?”

Response: “Associated communication systems” refer to communication systems used to convey essential Protection System tripping logic, sometimes referred to as pilot relaying or teleprotection. Examples include the following:

- communications equipment involved in power-line-carrier relaying;

- communications equipment involved in various types of permissive protection system applications;

- direct transfer-trip systems;

- digital communication systems ... .”

8. In its Petition requesting that the Commission accept the proposed interpretation, NERC recognized that greater clarity to the requirement language in PRC-005-1a is necessary to provide a complete framework for maintenance and testing of equipment necessary to ensure the reliability of the Bulk Power System. In its Petition, NERC also stated that this activity is already underway in the scope of Project 2007-17 – Protection System Maintenance and Testing, coupled with the revised definition of Protection System.

IV. Commission NOPR

9. In the NOPR, the Commission proposed to accept the NERC proposed interpretation of Requirement R1 of Reliability Standard PRC-005-1. In addition, the Commission proposed to direct NERC to develop modifications to the PRC-005-1 Reliability Standard through its Reliability Standards development process to address gaps in the Protection System maintenance and testing standard that were highlighted by the proposed interpretation. The specific modifications are discussed below.

V. Comments

10. Comments on the Commission's proposed interpretation were received by the NERC, Edison Electric Institute (EEI), ISO/RTO Council (IRC), American Public Power Association (APPA), National Rural Electric Cooperative Association (NRECA), Transmission Access Policy Study Group (TAPS), Cities of Anaheim and Riverside,

California (Joint Cities), Northwest Commenters,[14] International Transmission Company (ITC), PSEG Companies,[15] and MidAmerican Energy Holdings Company (MidAmerican), Constellation/CENG,[16] and Manitoba Hydro (Manitoba). In general, commenters support NERC's proposed interpretation, and oppose the further directives in the NOPR. Commenters also state that modifications to the Reliability Standards should be addressed within the NERC standards development process and that certain of the modifications are currently being addressed.

VI. <u>Discussion</u>

11. As a result of the comments received in response to the proposal, the Commission adopts the NOPR proposal to accept NERC's proposed interpretation. As discussed below,[17] the Commission accepts, in part, NERC's commitments to address the concerns

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[14] Lincoln People's Utility District, Columbia River People's Utility District, Inland Power and Light Company, Northwest Public Power Association, Northwest Requirements Utilities, Pacific Northwest Generating Cooperative, Public Power Council, Public Utility District No. 1 of Snohomish County, and Tillamook People's Utility District.

[15] Public Service Electric and Gas Company, PSEG Fossil LLC, and PSEG Nuclear LLC.

[16] Constellation Energy Group, Inc., Baltimore Gas & Electric Company, Constellation Energy Commodities Group, Inc., Constellation Energy Control and Dispatch, LLC, Constellation NewEnergy, Inc., and Constellation Power Source Generation, Inc. (together, Constellation) and Constellation Energy Nuclear Group, LLC (CENG).

[17] *See infra*, P 15, P 18, P 20.

in the Protection System maintenance and testing standard that were identified by the NOPR within the Reliability Standards development process, and directs, in part, that the concerns identified by the NOPR with regard to reclosing relays be addressed within the reinitiated PRC-005 revisions.

A. Maintenance and Testing of Auxiliary and Non-Electrical Sensing Relays

12. In the NOPR, the Commission noted a concern that the proposed interpretation may not include all components that serve in some protective capacity.[18] The Commission's concerns included the proposed interpretation's exclusion of auxiliary and non-electrical sensing relays. The Commission proposed to direct NERC to develop a modification to the Reliability Standard to include any component or device that is designed to detect defective lines or apparatuses or other power system conditions of an abnormal or dangerous nature, including devices designed to sense or take action against any abnormal system condition that will affect reliable operation, and to initiate appropriate control circuit actions.

13. In their comments NERC, EEI, Joint Cities, Manitoba, NRECA, ITC, MidAmerican, and PSEG expressed varying levels of disagreement with the NOPR's proposed directive. The disagreements are based on a concern that the proposed directive

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[18] NOPR at P 11-14.

will create an increase in scope that will capture many items not used in BES protection. NERC is concerned the scope of this proposed directive is so broad that any device that is installed on the Bulk-Power System to monitor conditions in any fashion may be included. [19] NERC states that many of these devices are advisory in nature and should not be reflected within NERC Reliability Standards if they do not serve a necessary reliability purpose.[20] NERC does not believe it is necessary for the Commission to issue a directive to address this issue. Instead, NERC proposes to develop, either independently or in association with other technical organizations such as IEEE, one or more technical documents which:

1. describe the devices and functions (to include sudden pressure relays which trip for fault conditions) that should address FERC's concern; and
2. propose minimum maintenance activities for such devices and maximum maintenance intervals, including the technical basis for each.[21]

14. NERC states that these technical documents will address those protective relays that are necessary for the reliable operation of the Bulk-Power System and will allow for differentiation between protective relays that detect faults from other devices that monitor

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[19] NERC February 25, 2011 Comments at 7.

[20] *Id.*

[21] *Id.*

the health of the individual equipment and are advisory in nature (e.g., oil temperature). Following development of the above-referenced document(s), NERC states that it will "propose a new or revised standard (e.g. PRC-005) using the NERC Reliability Standards development process to include maintenance of such devices, including establishment of minimum maintenance activities and maximum maintenance intervals."[22] Accordingly, NERC proposes to "add this issue to the Reliability Standards issues database for inclusion in the list of issues to address the next time the PRC-005 standard is revised."[23]

15. The Commission accepts NERC's proposal, and directs NERC to file, within sixty days of publication of this Final Rule, a schedule for informational purposes regarding the development of the technical documents referenced above, including the identification of devices that are designed to sense or take action against any abnormal system condition that will affect reliable operation. NERC shall include in the informational filing a schedule for the development of the changes to the standard that NERC stated it would propose as a result of the above-referenced documents.[24] NERC should update its schedule when it files its annual work plan.

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[22] *Id.*

[23] *Id.*

[24] *Id.* at 7, 8.

B. Reclosing Relays

16. In the NOPR, the Commission noted that while a reclosing relay is not identified as a specific component of the Protection System, if it either is used in coordination with a Protection System to achieve or meet system performance requirements established in other Commission–approved Reliability Standards, or can exacerbate fault conditions when not properly maintained and coordinated, then excluding the maintenance and testing of these reclosing relays will result in a gap in the maintenance and testing of relays affecting the reliability of the Bulk-Power System.[25] Accordingly, the Commission proposed that NERC modify the Reliability Standard to include the maintenance and testing of reclosing relays affecting the reliability of the Bulk-Power System.

17. NERC, EEI, IRC, ITC MidAmerican, NRECA, and PSEG opposed the NOPR's directive to include reclosing relays. In general, commenters state that reclosing relays used for stability purposes are already included in maintenance and testing programs, and that reclosing relays that are primarily used to minimize customer outages times and maximize availability of system components should not be included. PSEG and MidAmerican contend that the NERC standards development process should be utilized

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[25] NOPR at P 15.

to determine the maintenance and testing of those reclosing relays that affect the reliability of the Bulk-Power System.

18. ISO/RTO contends that the primary purpose of reclosing relays is to allow more expeditious restoration of lost components of the system, not to maintain the reliability of the Bulk-Power System. Therefore, ISO/RTO maintains that automatic reclosing relays should not be subject to the NERC Reliability Standard for relay maintenance and testing. MidAmerican states that there are only limited circumstances when a reclosing relay can actually affect the reliability of the Bulk-Power System. MidAmerican contends that it would be overbroad for the Commission to direct a modification to the standard that encompasses all reclosing relays that can "exacerbate fault conditions when not properly maintained and coordinated," as this would improperly include many types of reclosing relays that do not necessarily affect the reliability of the Bulk-Power System.

19. ITC agrees with the Commission's proposal that reclosing relays that are required for system stability should be maintained and tested under Requirement R1 of PRC-005-1. However, ITC contends that since most bulk electric system automatic reclosing relay systems are applied to minimize customer outage times and to maximize availability of system components, only some "high speed" reclosing relays will affect the reliability of the Bulk-Power System. Therefore, ITC proposes that the Commission should direct NERC to draft specific requirements or selection criteria that should be used in

identifying the types of re-closing relays for maintenance and testing under Requirement R1 of PRC-005-1.[26]

20. While NRECA notes that reclosing relays operate to restore, not protect a system, NRECA also notes that there are reclosing schemes that directly affect and are required for automatic stability control of the system, but that such schemes are already covered under Special Protection Schemes that are subject to reliability standards. NRECA, notes that some transmission operators do not allow reclosing relays on the bulk power system to remove the possibility of reclosing in on a permanent fault, thus avoiding further potential damage to the bulk power system.[27]

21. Similarly, NERC comments that in most cases reclosing relays cannot be relied on to meet system performance requirements because of the need to consider the impact of auto-reclosing into a permanent fault; however, NERC states that applications that may exist in which automatic restoration is used to meet system performance requirements following temporary faults. NERC comments that where reclosing relays are applied to meet performance requirements in approved NERC Reliability Standards, or where automatic restoration of service is fundamental to derivation of an Interconnection Reliability Operating Limit (IROL), it is reasonable to require maintenance and testing of

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[26] ITC Comments at 7.

[27] NRECA Comments at 13-14.

auto-reclosing relays.[28] However, NERC does not believe it is necessary for the Commission to issue a directive.[29] NERC states that the proposed revisions to Reliability Standard PRC-005-1 that are under development include maintenance of reclosing devices that are part of Special Protection Systems.[30] NERC proposes “to add the remaining concerns relating to this issue to the Reliability Standards issues database for inclusion in the list of issues to address the next time Reliability Standard PRC-005 is revised.”[31]

22. As NERC and other commenters point out, reclosing relays are used in a broad range of applications; e.g., meet system performance requirements in approved Reliability Standards, derivation of IROLs, maintain system stability, minimize customer outage times, to maximize availability of system components, etc. While commenters acknowledge that reclosing relays have several applications, commenters also appear to be divided on which applications, if any, should be included in a maintenance and testing program.

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[28] NERC February 25, 2011 Comments at 9.

[29] TAPs urges the Commission to use its authority pursuant to section 215(d)(5) in circumstances where there is a clear need for such a directive.

[30] *Id.*

[31] *Id.*

23. The NOPR raised a concern that excluding the maintenance and testing of reclosing relays that can exacerbate fault conditions when not properly maintained and coordinated will result in a gap affecting Bulk-Power System reliability.[32] We agree with MidAmerican that while there are only limited circumstances when a reclosing relay can actually affect the reliability of the Bulk-Power System, there are some reclosing relays, e.g., whose failure to operate or that misoperate during an event due to lack of maintenance and testing, may negatively impact the reliability of the Bulk-Power System.[33] We agree with NERC that where reclosing relays are applied to meet performance requirements in approved NERC Reliability Standards, or where automatic restoration of service is fundamental to derivation of an Interconnection Reliability Operating Limit (IROL), it is reasonable to require maintenance and testing of auto-reclosing relays.

24. In the NOPR we stated that a misoperating or miscoordinated reclosing relay may result in the reclosure of a Bulk-Power System element back onto a fault or that a misoperating or miscoordinated reclosing relay may fail to operate after a fault has been cleared, thus failing to restore the element to service. As a result, the reliability of the

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[32] NOPR at P 15, noting one such outage resulting in the loss of over 4,000 MW of generation and multiple 765 kV lines.

[33] MidAmerican Comments at 6.

Bulk-Power System would be affected. In addition, misoperated or miscoordinated relays may result in damage to the Bulk-Power System. For example, a misoperation or miscoordination of a reclosing relay causing the reclosing of Bulk-Power System facilities into a permanent fault can subject generators to excessive shaft torques and winding stresses and expose circuit breakers to systems conditions less than optimal for correct operation, potentially damaging the circuit breaker.[34]

25. While some commenters argue that reclosing relays do not affect the reliability of the Bulk-Power System, the record supports our concern. For example, we note NERC's concern regarding the "… need to consider the impact of autoreclosing into a permanent fault." We also note NRECA's comments that "… some transmission operators do not allow reclosing on the bulk electric system facilities to remove the opportunity of closing in on a permanent fault" and "… by its [automatic reclosing] use a utility understands the potential for further damage that may occur by reclosing."[35] Because the misoperation or miscommunication of reclosing relays can exacerbate fault conditions, we find that

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[34] NERC System Protection and Control Subcommittee, "Advantages and Disadvantages of EHV Automatic Reclosing, "December 9, 2009, p. 14.

[35] NRECA Comments at 13.

reclosing relays that may affect the reliability of the Bulk-Power System should be maintained and tested.[36]

26. For the reasons discussed above, we conclude that it is important to maintain and test reclosing relays that may affect the reliability of the Bulk-Power System. We agree with ITC that specific requirements or selection criteria should be used to identify reclosing relays that affect the reliability of the Bulk-Power System. As MidAmerican suggests, the standard should be modified, through the Reliability Standards development process, to provide the Transmission Owner, Generator Owner, and Distribution Provider with the discretion to include in a Protection System maintenance and testing program only those reclosing relays that the entity identifies as having an affect on the reliability of the Bulk-Power System.

27. We note that the original project to revise Reliability Standard PRC-005 failed a recirculation ballot in July of 2011. The project was subsequently reinitiated to continue the efforts to develop Reliability Standard PRC-005-2. Given that the project to draft proposed revisions to Reliability Standard PRC-005-1 continues in this reinitiated effort, and the importance of maintaining and testing reclosing relays, we direct NERC to include maintenance and testing of reclosing relays that can affect the reliable operation

[36] As NERC notes, there may be applications of reclosing relays where the misoperation or miscommunication may does not have a detrimental effect on the reliability of the Bulk-Power System.

of the Bulk-Power System, as discussed above, within these reinitiated efforts to revise Reliability Standard PRC-005.[37]

C. DC Control Circuitry and Components

28. In the NOPR, the Commission explained its understanding that a maintenance and testing program for DC control circuitry would include all components of DC control circuitry necessary for ensuring Reliable Operation of the Bulk-Power System, and that not establishing the specific requirements of such a maintenance and testing program results in a gap in the maintenance and testing of Protection System components.[38]

29. Joint Cities, MidAmerican, and NRECA expressed concern that the NOPR's directive is too broad and unnecessarily burdensome. NERC agrees that maintenance and testing should be required for all DC control circuitry.[39] NERC further stated that draft standard PRC-005-2 being developed in Project 2007-17 "includes extensive, specific maintenance activities (with maximum maintenance intervals) related to the DC control

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[37] On December 13, 2011, NERC submitted its Standards Development Plan for 2012-2014. NERC estimates that Project 2007-17 will be completed in the second quarter of 2012. By July 30, 2012, NERC should submit to the Commission either the completed project which addresses the remaining issues consistent with this order, or an informational filing that provides a schedule for how NERC will address such issues in the Project 2007-17 reinitiated efforts.

[38] NOPR at P 16.

[39] NERC February 25, 2011 Comments at 10.

circuits."[40] The Commission accepts NERC's commitment to include the development of specific requirements of such a maintenance and testing program described above in Project 2007-17.[41]

VII. Information Collection Statement

30. The Office of Management and Budget (OMB) regulations require that OMB approve certain reporting and recordkeeping (collections of information) imposed by an agency.[42] The Commission submits reporting and recording keeping requirements to OMB under section 3507 of the Paperwork Reduction Act of 1995.[43]

31. As stated above, the Commission previously approved, in Order No. 693, the Reliability Standard that is the subject of the current Final Rule. This Final Rule accepts an interpretation of the currently approved Reliability Standard. The interpretation of the current Reliability Standard at issue in this final rule is not expected to change the reporting burden or the information collection requirements. The informational filing

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[40] *Id.*

[41] As previously noted, NERC estimates that Project 2007-17 will be completed by the second quarter of 2012. By July 30, 2012, NERC should submit to the Commission either the completed project which addresses the remaining issues consistent with this order, or an informational filing that provides a schedule for how NERC will address such issues in the Project 2007-17 reinitiated efforts.

[42] 5 CFR 1320.

[43] 44 U.S.C. 3507.

required of NERC is part of currently active collection FERC-725 and does not require additional approval by OMB.

32. We will submit this final rule to OMB for informational purposes only.

VIII. Environmental Analysis

33. The Commission is required to prepare an Environmental Assessment or an Environmental Impact Statement for any action that may have a significant adverse effect on the human environment.[44] The Commission has categorically excluded certain actions from this requirement as not having a significant effect on the human environment. Included in the exclusion are rules that are clarifying, corrective, or procedural or that do not substantially change the effect of the regulations being amended.[45] The actions proposed herein fall within this categorical exclusion in the Commission's regulations.

IX. Regulatory Flexibility Act

34. The Regulatory Flexibility Act of 1980 (RFA) generally requires a description and analysis of final rules that will have significant economic impact on a substantial number of small entities.[46] The RFA mandates consideration of regulatory alternatives that

[44] *Regulations Implementing the National Environmental Policy Act of 1969*, Order No. 486, FERC Stats. & Regs. ¶ 30,783 (1987).

[45] 18 CFR 380.4(a)(2)(ii).

[46] 5 U.S.C. 601-612.

accomplish the stated objectives of a proposed rule and that minimize any significant economic impact on a substantial number of small entities. The Small Business Administration's (SBA) Office of Size Standards develops the numerical definition of a small business.[47] The SBA has established a size standard for electric utilities, stating that a firm is small if, including its affiliates, it is primarily engaged in the transmission, generation and/or distribution of electric energy for sale and its total electric output for the preceding twelve months did not exceed four million megawatt hours.[48] The RFA is not implicated by this Final Rule because the interpretation accepted herein does not modify the existing burden or reporting requirements. Because this Final Rule accepts an interpretation of the currently approved Reliability Standard, the Commission certifies that this Final Rule will not have a significant economic impact on a substantial number of small entities.

X. Document Availability

35. In addition to publishing the full text of this document in the Federal Register, the Commission provides all interested persons an opportunity to view and/or print the contents of this document via the Internet through FERC's Home Page (http://www.ferc.gov) and in FERC's Public Reference Room during normal business

[47] 13 CFR 121.201.

[48] *Id.* n.1.

hours (8:30 a.m. to 5:00 p.m. Eastern time) at 888 First Street, NE, Room 2A, Washington, DC 20426.

36. From FERC's Home Page on the Internet, this information is available on eLibrary. The full text of this document is available on eLibrary in PDF and Microsoft Word format for viewing, printing, and/or downloading. To access this document in eLibrary, type the docket number excluding the last three digits of this document in the docket number field.

37. User assistance is available for eLibrary and the FERC's website during normal business hours from FERC Online Support at 202-502-6652 (toll free at 1-866-208-3676) or email at ferconlinesupport@ferc.gov, or the Public Reference Room at (202) 502-8371, TTY (202) 502-8659. E-mail the Public Reference Room at public.referenceroom@ferc.gov.

XI. Effective Date and Congressional Notification

38. This Final Rule is effective 30 days from publication in Federal Register. The Commission has determined, with the concurrence of the Administrator of the Office of Information and Regulatory Affairs of OMB that this rule is not a "major rule" as defined in section 351 of the Small Business Regulatory Enforcement Fairness Act of 1996.

List of subjects in 18 CFR Part 40

Applicability
Mandatory Reliability Standards
Availability of Reliability Standards

By the Commission.

(S E A L)

Nathaniel J. Davis, Sr.,
Deputy Secretary.

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

INTERPRETATION OF PROTECTION SYSTEM RELIABILITY STANDARD	**)** **)**	**Docket No. RM10-5-000**

COMMENTS OF THE
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION
IN RESPONSE TO NOTICE OF PROPOSED RULEMAKING

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February 25, 2011

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I. INTRODUCTION

The North American Electric Reliability Corporation ("NERC")[1] hereby provides these comments in response to the Federal Energy Regulatory Commission's ("FERC" or "Commission") Notice of Proposed Rulemaking ("NOPR")[2] regarding an interpretation of Requirement R1 of Reliability Standard PRC-005-1 — Transmission and Generation Protection System Maintenance and Testing. In the NOPR, the Commission proposed to approve the interpretation to Reliability Standard PRC-005-1 developed and approved by NERC, and proposed to direct NERC to develop modifications to the PRC-005-1 Reliability Standard to address proposed gaps in the Protection System maintenance and testing standard.

The stated purpose of PRC-005-1 is to ensure all transmission and generation Protection Systems affecting the reliability of the Bulk Electric System (BES) are maintained and tested. The proposed interpretation clarifies what equipment is to be included in the maintenance and testing programs specified by requirement R1 with reference to the definition of Protection System in the NERC Glossary of Terms. By this filing, NERC submits its response to the NOPR.

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[1] The Federal Energy Regulatory Commission ("FERC" or "Commission") certified NERC as the electric reliability organization ("ERO") in its order issued on July 20, 2006 in Docket No. RR06-1-000. *North American Electric Reliability Corporation*, "Order Certifying North American Electric Reliability Corporation as the Electric Reliability Organization and Ordering Compliance Filing," 116 FERC ¶ 61,062 (July 20, 2006).
[2] *Interpretation of Protection System Reliability Standard*, 133 FERC ¶ 61,223 (December 16, 2010) ("NOPR").

II. NOTICES AND COMMUNICATIONS

Notices and communications with respect to this filing may be addressed to:

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III. DISCUSSION

In a November 17, 2009 filing,[3] NERC requested Commission approval of a proposed interpretation to Reliability Standard PRC-005-1. The interpretation was developed in response to a request for interpretation submitted to NERC by the Regional Entities Compliance Monitoring Processes Working Group ("Working Group").[4] The interpretation included five specific questions, and the interpretation development team provided a response to all five of the Working Group's questions.

The proposed interpretation helps to ensure that the intent of the standard is supported through effective compliance monitoring. Protection Systems are a critical line of defense essential to the reliability of the bulk power system. Because the failure of Protection Systems can cause catastrophic events, preventive maintenance is critical to reliability. The proposed interpretation

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[3] *See* NERC**,** *Petition of the North American Electric Reliability Corporation for Approval of Interpretation to Reliability Standard PRC- 005-1 — Transmission and Generation Protection System Maintenance and Testing, Requirement R1*, Docket No. RM06-16-000 (November 17, 2009)

[4] The Working Group is a subcommittee of the Regional Entity Management Group which consists of the executive management of the eight Regional Entities.

supports the reliability objective of the standard by providing greater certainty and clarity regarding the equipment that must be maintained in support of this objective. NERC agrees with and supports the Commission's proposal to approve the proposed interpretation of Requirement R1 to PRC-005-1.

A. Responses to the Commission's Requests for Additional Information and Comment

1. Modify the Reliability Standard to Include Any Component or Device that is Designed to Detect Defective Lines or Apparatuses or Other Power System Conditions of an Abnormal or Dangerous Nature and to Initiate Appropriate Control Circuit Actions

In the NOPR, the Commission states that while it is proposing to approve the interpretation to PRC-005-1, it is concerned that the interpretation highlights a gap in the Protection System Maintenance standard pursuant to Requirement R1 of PRC-005-1.[5] Specifically, the Commission expresses concern that, in order to prevent a gap in reliability, any component that detects any quantity needed to take an action, or that initiates any control action (initial tripping, reclosing, lockout, *etc.*), affecting the reliability of the bulk power system, should also be included as a component of a Protection System.[6] FERC therefore is proposing to direct NERC to develop a modification to the Reliability Standard to include any component or device that is designed to detect defective lines or apparatuses or other power system conditions of an abnormal or dangerous nature and to initiate appropriate control circuit actions.[7] Additionally, the Commission is proposing that all components that serve in some protective capacity to ensure reliable operation of the Bulk-Power System should be included within the definition of "Protection System" and should be maintained and tested accordingly – not just the

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[5] NOPR at P 11.
[6] *Id.*
[7] *Id.*

limited subset identified in the NERC interpretation.[8] The Commission requested comments on this general proposal.

NERC agrees that modifications to the standard are necessary to achieve the reliability objective of PRC-005-1 which is to ensure all transmission and generation Protection Systems affecting the reliability of the Bulk Electric System ("BES") are maintained and tested. NERC believes, however, that the modifications to PRC-005-1 already underway in Project 2007-17, coupled with NERC's recently revised definition of Protection System, address most of the issues raised in the NOPR.

NERC agrees that to achieve the reliability objective of PRC-005-1, the requirements must be applicable to all components that serve in some protective capacity to ensure reliable operation. To accomplish those needed improvements, NERC has underway the development of draft standard PRC-005-2 (Project 2007-17), which has recently been balloted for the second time. NERC believes the modifications to PRC-005 currently underway, coupled with NERC's recently revised definition of Protection System, address most of the issues raised in the NOPR. Therefore, while NERC agrees with the reliability-related intent of the proposed directive to modify PRC-005-1, and provides comments below in response to each specific request for which FERC has proposed to direct modifications to the standard, the work already underway will achieve the reliability-related intent of the Commission's proposed modifications to PRC-005-1. Accordingly, there is no need for the Commission to issue additional directives in response to the NOPR.[9]

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[8] *Id.*

[9] In Order No. 693 the Commission directed revisions to PRC-005-1 to require that maintenance and testing of a protection system must be carried out within a maximum allowable interval that is appropriate for the type of the protection system. *See*, *Mandatory* Reliability *Standards for the Bulk-Power System*, 118 FERC ¶ 61,218, FERC Stats. & Regs. ¶ 31,242 (2007) ("Order No. 693"), *order on reh'g*, *Mandatory Reliability Standards for the Bulk-Power System*, 120 FERC ¶ 61,053 ("Order No. 693-A") (2007).

2. Include Any Device, Including Auxiliary and Backup Protection Devices, That is Designed to Sense or Take Action Against Any Abnormal System Condition that will Affect Reliable Operation.

In the NOPR, FERC notes that NERC's proposed interpretation does not include in the existing definition of "Protection System" auxiliary relays, and that auxiliary relays need only be maintained if an entity's maintenance and testing program for DC control circuits involves maintenance and testing of imbedded auxiliary relays.[10] FERC states that these exclusions contradict the purpose statement of PRC-005-1, which provides that "all transmission and generation Protection Systems affecting the reliability of the BES are maintained and tested," and therefore will result in a gap in the maintenance and testing of Protection Systems affecting the reliability of the bulk power system.[11] The Commission therefore is requesting comments on whether it should direct NERC to include any device, including auxiliary and backup protection devices, that is designed to sense or take action against any abnormal system condition that will affect reliable operation, in the Reliability Standard.[12]

NERC agrees with the reliability-related intent of this proposed directive that auxiliary relays that can initiate a control action should be included within the definition of "Protection System," and notes that a modification to the NERC Glossary definition of "Protection System," which partially addresses the specific concerns regarding auxiliary relays by specifying that the control circuitry is through the tip coil of the interrupting device, was recently successfully balloted, was adopted by the NERC Board of Trustees on November 19, 2010, and will be filed with FERC for approval in the near future. Additionally, the draft PRC-005-2 standard includes

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[10] NOPR at PP 12-13.
[11] *Id.* at P12.
[12] *Id.* at P 14.

extensive, specific maintenance activities related to the communications equipment and DC control circuits (including auxiliary relays that can initiate a control action).

The implementation plan approved for the revised definition of Protection System proposed a 12 month delay to give entities time to apply the expanded scope of the definition of Protection System to the requirements in PRC-005-1. The revised definition of Protection System is:

- Protective relays which respond to electrical quantities;
- Communications systems necessary for correct operation of protective functions;
- Voltage and current sensing devices providing inputs to protective relays;
- Station DC supply associated with protective functions (including station batteries, battery chargers, and non-battery-based DC supply); and
- Control circuitry associated with protective functions through the trip coil(s) of the circuit breakers or other interrupting devices.

Furthermore, the draft PRC-005-2 Reliability Standard establishes maximum maintenance intervals in accordance with FERC's directives in Order No. 693 related to PRC-005-1,[13] PRC-008-0,[14] PRC-011-0,[15] and PRC-017-0.[16] Accordingly, the revised definition of Protection System coupled with the proposed revisions to the PRC-005-1 standard, already address FERC's reliability concerns regarding testing of auxiliary and backup protection devices and issuing a new directive is not necessary.

Regarding FERC's proposed directive to include in the Reliability Standard any device, including auxiliary and backup protection devices, that is designed to sense or take action against any abnormal system condition that will affect reliable operation, NERC understands FERC's concerns related to protective relays that do not respond to electrical quantities and agrees that sudden pressure relays which trip for fault conditions should be maintained in accordance with

[13] Order No. 693 at P 1475
[14] *Id.* at P 1492.
[15] *Id.* at P 1516.
[16] *Id.* at. P 1546.

NERC Reliability Standard requirements. However, NERC is not aware of any existing documents that establish a technical basis for either minimum maintenance activities or maximum maintenance intervals for these devices. NERC is concerned the scope of this proposed directive is so broad that any device that is installed on the bulk power system to monitor conditions in any fashion may be included. In fact, many of these devices are advisory in nature and should not be reflected within NERC Standards if they do not serve a necessary reliability purpose.

NERC therefore is proposing to develop, either independently or in association with other technical organizations such as IEEE, one or more technical documents which:

i. describe the devices and functions (to include sudden pressure relays which trip for fault conditions) that should address FERC's concern; and

ii. propose minimum maintenance activities for such devices and maximum maintenance intervals, including the technical basis for each.

These technical documents will address those protective relays that are necessary for the reliable operation of the bulk power system and will allow for differentiation between protective relays that detect faults from other devices that monitor the health of the individual equipment and are advisory in nature (*e.g.*, oil temperature). Following development of the above-referenced document(s), NERC will propose a new or revised standard (*e.g.*, PRC-005) using the NERC Reliability Standards development process to include maintenance of such devices, including establishment of minimum maintenance activities and maximum maintenance intervals. NERC does not believe it is necessary for the Commission to issue a directive to address this issue. Rather, NERC proposes to add this issue to the reliability standards issues database for inclusion in the list of issues to address the next time the PRC-005 standard is revised.

Because proposed changes to the definition of "Protection System" and revisions in the form of a draft standard PRC-005-2 will address many of the concerns the Commission raises, there is no need to issue a directive as proposed by the Commission in the NOPR. The one remaining issue needs to await the development of technical documents in support of any proposed change to a Reliability Standard dealing with other protective relays that do not respond to electrical quantities. NERC will propose appropriate changes to its standards once those technical papers are completed. There is nothing in this record to support giving this issue the priority treatment that would come from issuance of a directive under section 215(d)(5) on the matter.

3. Modify the Reliability Standard to Include the Maintenance and Testing of Reclosing Relays Affecting the Reliability of the Bulk Power System.

In the NOPR, the Commission notes that NERC's proposed interpretation does not identify reclosing relays as a specific component of the Protection System.[17] However, the Commission expresses concern that excluding the maintenance and testing of these reclosing relays will result in a gap in the maintenance and testing of relays affecting the reliability of the bulk power system.[18] The Commission therefore is requesting comments on whether a modification should be made to the Reliability Standard to include the maintenance and testing of reclosing relays affecting the reliability of the bulk power system.[19]

NERC understands that automatic restoration of faulted components is not mandated in the NERC Reliability Standards and observes that reclosing relays are most often applied to improve system availability, as a convenience to accelerate system restoration, or both. Mal-

[17] NOPR at P 15.
[18] *Id.*
[19] *Id.*

performance of reclosing relays so applied has no detrimental effect on the reliability of the bulk power system.

In most cases, autoreclosing cannot be relied on to meet system performance requirements because of the need to consider the impact of autoreclosing into a permanent fault. However, applications may exist in which automatic restoration is used to meet system performance requirements following temporary faults. In cases where autoreclosing relays are applied to meet performance requirements in approved NERC Reliability Standards, or where automatic restoration of service is fundamental to derivation of an Interconnection Reliability Operating Limit ("IROL"), it is reasonable to require maintenance and testing of autoreclosing relays.

NERC does not believe it is necessary for the Commission to issue a directive to address this issue. The proposed revisions to PRC-005-1 that are under development include maintenance of reclosing devices that are part of Special Protection Systems. NERC proposes to add the remaining concerns relating to this issue to the Reliability Standards issues database for inclusion in the list of issues to address the next time PRC-005 is revised.

4. Modify the Reliability Standard to Explicitly Include Maintenance and Testing of all DC Control Circuitry That is Necessary to Ensure Proper Operation of the Protection System, Including Voltage and Continuity.

In the NOPR, the Commission expresses concern that not establishing the specific requirements relative to the scope and/or methods for a maintenance and testing program for the DC circuitry results in a gap in the maintenance and testing of Protection System components affecting the reliability of the bulk power system.[20] FERC therefore is proposing to direct NERC to develop a modification to the Reliability Standard that explicitly includes maintenance and

[20] *Id.* at P 16.

testing of all DC control circuitry that is necessary to ensure proper operation of the Protection System, including voltage and continuity.[21]

NERC agrees that maintenance and testing should be required for all DC control circuitry. NERC's draft PRC-005-2 standard includes extensive, specific maintenance activities (with maximum maintenance intervals) related to the DC control circuits. These requirements also address detection of unintentional DC grounds with respect to FERC's concerns regarding insulation of the control circuitry.

NERC is uncertain whether the reference to DC control circuitry voltage is intended to include the need for sufficient insulation to maintain appropriate voltage, but observes that the draft PRC-005-2 standard addresses verification of the functionality of the DC control circuit. Accordingly, this aspect of the draft PRC-005-2 standard addresses FERC's concerns in this regard.

Because NERC's draft PRC-005-2 standard already includes provisions that address the Commission's concerns with respect to maintenance and testing of DC control circuitry, there is no need for the Commission to issue a directive on that subject.

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[21] *Id.*

IV. CONCLUSION

For the reasons stated above, NERC respectfully requests that the Commission take action consistent with these comments when it issues its Final Rule regarding the proposed interpretation to Reliability Standard PRC-005-1.

Respectfully submitted,

/s/ Holly. A Hawkins

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CERTIFICATE OF SERVICE

I hereby certify that I have served a copy of the foregoing document upon all parties listed on the official service list compiled by the Secretary in this proceeding.

Dated at Washington, D.C. this 25th day of February, 2011.

/s/ Holly A. Hawkins
Holly A. Hawkins
Attorney for North American Electric Reliability Corporation

Standards Announcement

Project 2007-17.3 Phase 3 of Protection System Maintenance and Testing (Sudden Pressure Relays) Standard Authorization Request for PRC-005-4

Informal Comment Period Now Open through March 14, 2014

Now Available

A 30-day informal comment period for the **Project 2007-17.3 – Phase 3 of Protection System Maintenance and Testing: PRC-005-4 (Sudden Pressure Relays)** Standard Authorization Request (SAR) is open through **8 p.m. Eastern on Friday, March 14, 2014.**

Instructions for Commenting

The comment period is open through **8 p.m. Eastern on Friday, March 14, 2014.** Please use the electronic form to submit comments on the SAR. If you experience any difficulties in using the electronic form, please contact Wendy Muller. An off-line, unofficial copy of the comment form is posted on the project page.

For information on the **Standards Development Process**, please refer to the Standard Processes Manual.

For more information or assistance, please contact Wendy Muller,
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Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Development Steps Completed

1. SAR posted for comment February 13, 2014 – March 14, 2014.

Description of Current Draft

The Protection System Maintenance and Testing Standard Drafting Team (PSMT SDT) is posting draft 1 of PRC-005-X for a 45-day comment period and ballot in the last ten days of the comment period under the new Standards Process Manual (Effective: June 26, 2013).

This draft contains the technical content of the standard. A parallel effort in the Project 2014-01, Standards Applicability for Dispersed Generation Resources, will post an applicability change to PRC-005-2 and PRC-005-3 for comment and ballot.

Anticipated Actions	Anticipated Date
45-day Formal Comment Period with Parallel Ballot	April 17 – June 2, 2014
45-day Additional Formal Comment Period with Parallel Ballot (if necessary)	July 21, – September 3, 2014
Final ballot	September 15, 2014
BOT adoption	November 2014

Definitions of Terms Used in Standard

This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the Reliability Standards Glossary of Terms (Glossary) are not repeated here. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, this defined term will be removed from the individual standard and added to the Glossary.

Protection System Maintenance Program (PSMP) — An ongoing program by which Protection System, Automatic Reclosing, and Sudden Pressure Relaying Components are kept in working order and proper operation of malfunctioning components is restored. A maintenance program for a specific Component includes one or more of the following activities:

- Verify — Determine that the Component is functioning correctly.
- Monitor — Observe the routine in-service operation of the Component.
- Test — Apply signals to a Component to observe functional performance or output behavior, or to diagnose problems.
- Inspect — Examine for signs of Component failure, reduced performance or degradation.
- Calibrate — Adjust the operating threshold or measurement accuracy of a measuring element to meet the intended performance requirement.

See Section A.6, Definitions Used in this Standard*,* for additional definitions that are new or modified for use within this standard.

When this standard has received ballot approval, the text boxes will be moved to the Application Guidelines Section of the Standard.

A. Introduction

1. **Title:** **Protection System, Automatic Reclosing, and Sudden Pressure Relaying Maintenance**
2. **Number:** **PRC-005-X**
3. **Purpose:** To document and implement programs for the maintenance of all Protection Systems, Automatic Reclosing, and Sudden Pressure Relaying affecting the reliability of the Bulk Electric System (BES) so that they are kept in working order.

Rationale for Applicability Section: This section does not reflect the applicability changes that will be proposed by the Project 2014-01 Standards Applicability for Dispersed Generation Resources standards drafting team.

4. **Applicability:**

4.1. Functional Entities:

4.1.1 Transmission Owner

4.1.2 Generator Owner

4.1.3 Distribution Provider

4.1.4 Balancing Authority

4.2. Facilities:

4.2.1 Protection Systems and Sudden Pressure Relaying that are installed for the purpose of detecting Faults on BES Elements (lines, buses, transformers, etc.)

4.2.2 Protection Systems used for underfrequency load-shedding systems installed per ERO underfrequency load-shedding requirements.

4.2.3 Protection Systems used for undervoltage load-shedding systems installed to prevent system voltage collapse or voltage instability for BES reliability.

4.2.4 Protection Systems installed as a Special Protection System (SPS) for BES reliability.

4.2.5 Protection Systems for generator Facilities that are part of the BES, including:

4.2.5.1 Protection Systems that act to trip the generator either directly or via lockout or auxiliary tripping relays.

4.2.5.2 Protection Systems and Sudden Pressure Relaying for generator step-up transformers for generators that are part of the BES.

4.2.5.3 Protection Systems for transformers connecting aggregated generation, where the aggregated generation is part of the BES (e.g., transformers connecting facilities such as wind-farms to the BES).

4.2.5.4 Protection Systems and Sudden Pressure Relaying for station service or excitation transformers connected to the generator bus of generators which are part of the BES, that act to trip the generator either directly or via lockout or tripping auxiliary relays.

4.2.6 Automatic Reclosing[1], including:

4.2.6.1 Automatic Reclosing applied on the terminals of Elements connected to the BES bus located at generating plant substations where the total installed gross generating plant capacity is greater than the gross capacity of the largest BES generating unit within the Balancing Authority Area.

4.2.6.2 Automatic Reclosing applied on the terminals of all BES Elements at substations one bus away from generating plants specified in Section 4.2.6.1 when the substation is less than 10 circuit-miles from the generating plant substation.

4.2.6.3. Automatic Reclosing applied as an integral part of an SPS specified in Section 4.2.4.

5. **Effective Date:** See Implementation Plan

6. **Definitions Used in this Standard:**

Automatic Reclosing – Includes the following Components:

- Reclosing relay
- Control circuitry associated with the reclosing relay.

Sudden Pressure Relaying – A system that trips an interrupting device(s) to isolate the equipment it is monitoring and includes the following Components:

[1] Automatic Reclosing addressed in Section 4.2.7.1 and 4.2.7.2 may be excluded if the equipment owner can demonstrate that a close-in three-phase fault present for twice the normal clearing time (capturing a minimum trip-close-trip time delay) does not result in a total loss of gross generation in the Interconnection exceeding the gross capacity of the largest BES generating unit within the Balancing Authority Area where the Automatic Reclosing is applied.

- Fault pressure relay – a mechanical relay or device that detects rapid changes in gas pressure, oil pressure, or oil flow that are indicative of Faults within liquid-filled, wire-wound equipment
- Control circuitry associated with a fault pressure relay

Unresolved Maintenance Issue – A deficiency identified during a maintenance activity that causes the Component to not meet the intended performance, cannot be corrected during the maintenance interval, and requires follow-up corrective action.

Segment – Components of a consistent design standard, or a particular model or type from a single manufacturer that typically share other common elements. Consistent performance is expected across the entire population of a Segment. A Segment must contain at least sixty (60) individual Components.

Component Type –

- Any one of the five specific elements of a Protection System.
- Any one of the two specific elements of Automatic Reclosing.
- Any one of the two specific elements of Sudden Pressure Relaying.

Rationale for the deletion of part of the definition of Component: The SDT determined that it was explanatory in nature and adequately addressed in the Supplementary Reference and FAQ Document.

Component – Any individual discrete piece of equipment included in a Protection System, Automatic Reclosing, or Sudden Pressure Relaying.

Countable Event – A failure of a Component requiring repair or replacement, any condition discovered during the maintenance activities in Tables 1-1 through 1-5, Table 3, Tables 4-1 through 4-2, and Table 5, which requires corrective action or a Protection System Misoperation attributed to hardware failure or calibration failure. Misoperations due to product design errors, software errors, relay settings different from specified settings, Protection System Component, Automatic Reclosing, or Sudden Pressure Relaying configuration or application errors are not included in Countable Events.

B. Requirements and Measures

R1. Each Transmission Owner, Generator Owner, and Distribution Provider shall establish a Protection System Maintenance Program (PSMP) for its Protection Systems, Automatic Reclosing, and Sudden Pressure Relaying identified in Section 4.2, Facilities. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning*]

The PSMP shall:

1.1. Identify which maintenance method (time-based, performance-based per PRC-005 Attachment A, or a combination) is used to address each Protection System, Automatic Reclosing, and Sudden Pressure Relaying Component Type. All batteries associated with the station dc supply Component Type of a Protection System shall be included in a time-based program as described in Table 1-4 and Table 3.

1.2. Include the applicable monitored Component attributes applied to each Protection System, Automatic Reclosing, and Sudden Pressure Relaying Component Type consistent with the maintenance intervals specified in Tables 1-1 through 1-5, Table 2, Table 3, Table 4-1 through 4-2, and Table 5 where monitoring is used to extend the maintenance intervals beyond those specified for unmonitored Protection System, Automatic Reclosing, and Sudden Pressure Relaying Components.

M1. Each Transmission Owner, Generator Owner and Distribution Provider shall have a documented Protection System Maintenance Program in accordance with Requirement R1.

For each Protection System, Automatic Reclosing, and Sudden Pressure Relaying Component Type, the documentation shall include the type of maintenance method applied (time-based, performance-based, or a combination of these maintenance methods), and shall include all batteries associated with the station dc supply Component Types in a time-based program as described in Table 1-4 and Table 3. (Part 1.1)

For Component Types that use monitoring to extend the maintenance intervals, the responsible entity(s) shall have evidence for each Protection System, Automatic Reclosing, and Sudden Pressure Relaying Component Type (such as manufacturer's specifications or engineering drawings) of the appropriate monitored Component attributes as specified in Tables 1-1 through 1-5, Table 2, Table 3, Table 4-1 through 4-2, and Table 5. (Part 1.2)

R2. Each Transmission Owner, Generator Owner, and Distribution Provider that uses performance-based maintenance intervals in its PSMP shall follow the procedure established in PRC-005 Attachment A to establish and maintain its performance-based intervals. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

M2. Each Transmission Owner, Generator Owner, and Distribution Provider that uses performance-based maintenance intervals shall have evidence that its current performance-based maintenance program(s) is in accordance with Requirement R2, which may include, but is not limited to, Component lists, dated maintenance records, and dated analysis records and results.

Rationale for R3 part 3.1 and 3.1.1.: The SDT, upon further reflection, determined that the PRC-005-3 Implementation Plan actually included a requirement that entities with newly-identified Automatic Reclosing Components implement its PSMP for those Components, and therefore determined that it was more appropriate to include this information in the standard rather than the implementation plan.

R3. Each Transmission Owner, Generator Owner, and Distribution Provider that utilizes time-based maintenance program(s) shall, except as provided in part 3.1, maintain its Protection System, Automatic Reclosing, and Sudden Pressure Relaying Components that are included within the time-based maintenance program in accordance with the minimum maintenance activities and maximum maintenance intervals prescribed within Tables 1-1 through 1-5, Table 2, Table 3, Table 4-1 through 4-2, and Table 5. *[Violation Risk Factor: High] [Time Horizon: Operations Planning]*

3.1. For each newly-identified Automatic Reclosing Component following a notification under Requirement R6, each Transmission Owner, Generator Owner, and Distribution Provider shall perform maintenance activities or provide documentation of prior maintenance activities according to either 3.1.1 or 3.1.2.

3.1.1. Complete the maintenance activities prescribed within Tables 4-1, 4-2(a), and 4-2(b) for the newly-identified Automatic Reclosing Component prior to the end of the third calendar year following the notification under Requirement R6; or

3.1.2. Provide documentation that the Automatic Reclosing Component was last maintained in accordance with the minimum maintenance activities and maximum maintenance intervals prescribed within Tables 4-1, 4-2(a), and 4-2(b).

M3. Each Transmission Owner, Generator Owner, and Distribution Provider that utilizes time-based maintenance program(s) shall have evidence that it has maintained its Protection System, Automatic Reclosing, and Sudden Pressure Relaying Components included within its time-based program in accordance with Requirement R3. The evidence may include, but is not limited to, dated maintenance records, dated maintenance summaries, dated check-off lists, dated inspection records, or dated work orders.

Rationale for R4 part 4.1 and 4.1.1.: The SDT, upon further reflection, determined that the PRC-005-3 Implementation Plan actually included a requirement that entities with newly-identified Automatic Reclosing Components implement its PSMP for those Components, and therefore determined that it was more appropriate to include this information in the standard rather than the implementation plan.

R4. Each Transmission Owner, Generator Owner, and Distribution Provider that utilizes performance-based maintenance program(s) in accordance with Requirement R2 shall, except as provided in part 4.1, implement and follow its PSMP for its Protection System, Automatic Reclosing, and Sudden Pressure Relaying Components that are included within the performance-based program(s). *[Violation Risk Factor: High] [Time Horizon: Operations Planning]*

4.1. For each newly-identified Automatic Reclosing Component following a notification under Requirement R6, each Transmission Owner, Generator Owner, and Distribution Provider shall perform maintenance activities or provide documentation of prior maintenance activities according to either 4.1.1 or 4.1.2.

4.1.1. Complete the maintenance activities prescribed within Tables 4-1, 4-2(a), and 4-2(b) for the newly-identified Automatic Reclosing Component prior to the end of the third calendar year following the notification under Requirement R6; or

4.1.2. Provide documentation that the Automatic Reclosing Component was last maintained in accordance with the minimum maintenance activities and maximum maintenance intervals prescribed within Tables 4-1, 4-2(a), and 4-2(b).

M4. Each Transmission Owner, Generator Owner, and Distribution Provider that utilizes performance-based maintenance intervals in accordance with Requirement R2 shall have evidence that it has implemented the Protection System Maintenance Program for the Protection System, Automatic Reclosing, and Sudden Pressure Relaying Components included in its performance-based program in accordance with Requirement R4. The evidence may include, but is not limited to, dated maintenance records, dated maintenance summaries, dated check-off lists, dated inspection records, or dated work orders.

R5. Each Transmission Owner, Generator Owner, and Distribution Provider shall demonstrate efforts to correct identified Unresolved Maintenance Issues. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

M5. Each Transmission Owner, Generator Owner, and Distribution Provider shall have evidence that it has undertaken efforts to correct identified Unresolved Maintenance Issues in accordance with Requirement R5. The evidence may include, but is not limited to, work orders, replacement Component orders, invoices, project schedules with completed milestones, return material authorizations (RMAs) or purchase orders.

Rationale for R6: The information addressed in Requirement R6 is necessary for Transmission Owners, Generator Owners, and Distribution Provides to accurately apply Section 4.2.7, Applicability. The Balancing Authority is the entity that maintains the information and should have the responsibility to provide this information to the applicable entities. The drafting team reconsidered the inclusion of the Balancing Authority and determined it is appropriate to include the requirement the standard. This requirement may be relocated to another standard during future reviews of standards for quality and content.

The periodicity was chosen to balance the needs of the Transmission Owner, Generator Owner, and Distribution Provider to obtain the information with the needs of the Balancing Authority to provide an accurate gross capacity (considering retirement or installation of generating units and/or changes in its Balancing Authority Area) in order to properly include Automatic Reclosing in a PSMP.

R6. Each Balancing Authority shall, at least once every calendar year with not more than 15 calendar months between notifications, notify each Transmission Owner, Generator Owner, and Distribution Provider within its Balancing Authority Area of the gross capacity, in MW or MVA, of the largest BES generating unit within the Balancing Authority Area. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

M6. Each Balancing Authority shall have dated documentation that it notified each Transmission Owner, Generator Owner, and Distribution Provider in accordance with Requirement R6. Examples of evidence may include, but are not limited to, copies of correspondence, such as e-mails or memoranda.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

As defined in the NERC Rules of Procedure, “Compliance Enforcement Authority” means NERC or the Regional Entity in their respective roles of monitoring and enforcing compliance with the NERC Reliability Standards.

1.2. Evidence Retention

The following evidence retention periods identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

The Transmission Owner, Generator Owner, Distribution Provider, and Balancing Authority shall each keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

For Requirement R1, the Transmission Owner, Generator Owner, and Distribution Provider shall each keep its current dated Protection System

Maintenance Program, as well as any superseded versions since the preceding compliance audit, including the documentation that specifies the type of maintenance program applied for each Protection System Component Type.

For Requirement R2, Requirement R3, Requirement R4, and Requirement R5, the Transmission Owner, Generator Owner, and Distribution Provider shall each keep documentation of the most recent performance of each distinct maintenance activity for the Protection System, Automatic Reclosing, or Sudden Pressure Relaying Component, or all performances of each distinct maintenance activity for the Protection System, Automatic Reclosing, or Sudden Pressure Relaying Component since the previous scheduled audit date, whichever is longer.

For Requirement R6, the Balancing Authority shall keep documentation for three calendar years that it provided information identifying the largest BES generating unit to the Transmission Owners, Generator Owners, and Distribution Providers in its Balancing Authority Area.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.3. Compliance Monitoring and Assessment Processes:

Compliance Audits

Self-Certifications

Spot Checking

Compliance Violation Investigations

Self-Reporting

Complaints

1.4. Additional Compliance Information

None

Table of Compliance Elements

Requirement Number	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	The entity's PSMP failed to specify whether one Component Type is being addressed by time-based or performance-based maintenance, or a combination of both (part 1.1).	The entity's PSMP failed to specify whether two Component Types are being addressed by time-based or performance-based maintenance, or a combination of both (part 1.1).	The entity's PSMP failed to specify whether three Component Types are being addressed by time-based or performance-based maintenance, or a combination of both. (part 1.1). OR The entity's PSMP failed to include the applicable monitoring attributes applied to each Component Type consistent with the maintenance intervals specified in Tables 1-1 through 1-5, Table 2, Table 3, Tables 4-1 through 4-2, and Table 5 where monitoring is used to extend the maintenance intervals beyond those specified for unmonitored Components (part 1.2).	The entity failed to establish a PSMP. OR The entity's PSMP failed to specify whether four or more Component Types are being addressed by time-based or performance-based maintenance, or a combination of both (part 1.1). OR The entity's PSMP failed to include applicable station batteries in a time-based program (part 1.1).
R2	The entity uses performance-based maintenance intervals in its PSMP but failed to reduce Countable Events to no more than 4% within three years.	NA	The entity uses performance-based maintenance intervals in its PSMP but failed to reduce Countable Events to no more than 4% within four years.	The entity uses performance-based maintenance intervals in its PSMP but: 1) Failed to establish the technical justification described within Requirement R2 for the initial use of the performance-based PSMP OR 2) Failed to reduce Countable Events to no more than 4% within five years OR

Requirement Number	Lower VSL	Moderate VSL	High VSL	Severe VSL
				3) Maintained a Segment with less than 60 Components OR 4) Failed to: • Annually update the list of Components, OR • Annually perform maintenance on the greater of 5% of the Segment population or 3 Components, OR • Annually analyze the program activities and results for each Segment.
R3	For Components included within a time-based maintenance program, the entity failed to maintain 5% or less of the total Components included within a specific Component Type in accordance with the minimum maintenance activities and maximum maintenance intervals prescribed within Tables 1-1 through 1-5, Table 2, Table 3, Tables 4-1 through 4-2, and Table 5. For Automatic Reclosing Components added to a time-based maintenance program per information from the Balancing	For Components included within a time-based maintenance program, the entity failed to maintain more than 5% but 10% or less of the total Components included within a specific Component Type in accordance with the minimum maintenance activities and maximum maintenance intervals prescribed within Tables 1-1 through 1-5, Table 2, Table 3, Tables 4-1 through 4-2, and Table 5. For Automatic Reclosing Components added to a time-based maintenance program per	For Components included within a time-based maintenance program, the entity failed to maintain more than 10% but 15% or less of the total Components included within a specific Component Type in accordance with the minimum maintenance activities and maximum maintenance intervals prescribed within Tables 1-1 through 1-5, Table 2, Table 3, Tables 4-1 through 4-2, and Table 5. For Automatic Reclosing Components added to a time-based maintenance program per	For Components included within a time-based maintenance program, the entity failed to maintain more than 15% of the total Components included within a specific Component Type in accordance with the minimum maintenance activities and maximum maintenance intervals prescribed within Tables 1-1 through 1-5, Table 2, Table 3, Tables 4-1 through 4-2, and Table 5. For Automatic Reclosing Components added to a time-

Requirement Number	Lower VSL	Moderate VSL	High VSL	Severe VSL
	Authority, the entity failed to maintain 5% or less of the total Components in accordance with the minimum maintenance activities and maximum maintenance intervals prescribed within Tables 4-1 through 4-2.	information from the Balancing Authority, the entity failed to maintain more than 5% but 10% or less of the total Components in accordance with the minimum maintenance activities and maximum maintenance intervals prescribed within Tables 4-1 through 4-2.	information from the Balancing Authority, the entity failed to maintain more than 10% but 15% or less of the total Components in accordance with the minimum maintenance activities and maximum maintenance intervals prescribed within Tables 4-1 through 4-2.	based maintenance program per information from the Balancing Authority, the entity failed to maintain more than 15% of the total Components in accordance with the minimum maintenance activities and maximum maintenance intervals prescribed within Tables 4-1 through 4-2.
R4	For Components included within a performance-based maintenance program, the entity failed to maintain 5% or less of the annual scheduled maintenance for a specific Component Type in accordance with their performance-based PSMP. For Automatic Reclosing Components added to a performance-based maintenance program per information from the Balancing Authority, the entity failed to maintain 5% or less of the total Components in accordance with their performance-based PSMP.	For Components included within a performance-based maintenance program, the entity failed to maintain more than 5% but 10% or less of the annual scheduled maintenance for a specific Component Type in accordance with their performance-based PSMP. For Automatic Reclosing Components added to a performance-based maintenance program per information from the Balancing Authority, the entity failed to maintain more than 5% but 10% or less of the total Components in accordance with their performance-based PSMP.	For Components included within a performance-based maintenance program, the entity failed to maintain more than 10% but 15% or less of the annual scheduled maintenance for a specific Component Type in accordance with their performance-based PSMP. For Automatic Reclosing Components added to a performance-based maintenance program per information from the Balancing Authority, the entity failed to maintain more than 10% but 15% or less of the total Components in accordance with their performance-based PSMP.	For Components included within a performance-based maintenance program, the entity failed to maintain more than 15% of the annual scheduled maintenance for a specific Component Type in accordance with their performance-based PSMP. For Automatic Reclosing Components added to a performance-based maintenance program per information from the Balancing Authority, the entity failed to maintain more than 15% of the total Components in accordance with their performance-based PSMP.

Requirement Number	Lower VSL	Moderate VSL	High VSL	Severe VSL
R5	The entity failed to undertake efforts to correct 5 or fewer identified Unresolved Maintenance Issues.	The entity failed to undertake efforts to correct greater than 5 but less than or equal to 10 identified Unresolved Maintenance Issues.	The entity failed to undertake efforts to correct greater than 10 but less than or equal to 15 identified Unresolved Maintenance Issues.	The entity failed to undertake efforts to correct greater than 15 identified Unresolved Maintenance Issues.
R6				The entity failed to notify each Transmission Owner, Generator Owner, and Distribution Provider within its Balancing Authority Area at least once every calendar year of the gross capacity, in MW or MVA, of the largest BES generating unit within the Balancing Authority Area. OR The entity had more than 15 calendar months between notifications to each Transmission Owner, Generator Owner, and Distribution Provider of the gross capacity, in MW or MVA, of the largest BES generating unit within the Balancing Authority Area.

D. Regional Variances

None.

E. Interpretations

None.

F. Supplemental Reference Documents

The following documents present a detailed discussion about determination of maintenance intervals and other useful information regarding establishment of a maintenance program.

1. *Supplementary Reference and FAQ - PRC-005-X Protection System Maintenance,* Protection System Maintenance and Testing Standard Drafting Team (April 2014)
2. *Considerations for Maintenance and Testing of Auto-reclosing Schemes*, NERC System Analysis and Modeling Subcommittee, and NERC System Protection and Control Subcommittee (November 2012)

Sudden Pressure Relays and Other Devices that Respond to Non-Electrical Quantities – SPCS Input for Standard Development in Response to FERC Order No. 758, NERC System Protection and Control Subcommittee (December 2013)

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
1	December 1, 2005	1. Changed incorrect use of certain hyphens (-) to “en dash” (–) and “em dash (—).” 2. Added “periods” to items where appropriate. 3. Changed “Timeframe” to “Time Frame” in item D, 1.2.	01/20/05
1a	February 17, 2011	Added Appendix 1 - Interpretation regarding applicability of standard to protection of radially connected transformers	Project 2009-17 interpretation
1a	February 17, 2011	Adopted by Board of Trustees	

1a	September 26, 2011	FERC Order issued approving interpretation of R1 and R2 (FERC's Order is effective as of September 26, 2011)	
1.1a	February 1, 2012	Errata change: Clarified inclusion of generator interconnection Facility in Generator Owner's responsibility	Revision under Project 2010-07
1b	February 3, 2012	FERC Order issued approving interpretation of R1, R1.1, and R1.2 (FERC's Order dated March 14, 2012). Updated version from 1a to 1b.	Project 2009-10 Interpretation
1.1b	April 23, 2012	Updated standard version to 1.1b to reflect FERC approval of PRC-005-1b.	Revision under Project 2010-07

1.1b	May 9, 2012	PRC-005-1.1b was adopted by the Board of Trustees as part of Project 2010-07 (Generator Requirements at the Transmission Interface).	
2	November 7, 2012	Adopted by Board of Trustees	Project 2007-17 - Complete revision, absorbing maintenance requirements from PRC-005-1.1b, PRC-008-0, PRC-011-0, PRC-017-0
2	October 17, 2013	Errata Change: The Standards Committee approved an errata change to the implementation plan for PRC-005-2 to add the phrase "or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities;" to the second sentence under the "Retirement of Existing	
3	November 7, 2013	Adopted by the NERC Board of Trustees	Revised to address the FERC directive in Order No.758 to include Automatic Reclosing in maintenance programs.
3.1	February 12, 2014	Approved by the Standards Committee	Errata changes to correct capitalization of defined terms
4			Project 2007-17.3 – Revised to address the FERC directive in Order No. 758 to include sudden pressure relays in maintenance programs.

Table 1-1 Component Type - Protective Relay Excluding distributed UFLS and distributed UVLS (see Table 3)		
Component Attributes	**Maximum Maintenance Interval[2]**	**Maintenance Activities**
Any unmonitored protective relay not having all the monitoring attributes of a category below.	6 Calendar Years	For all unmonitored relays: • Verify that settings are as specified For non-microprocessor relays: • Test and, if necessary calibrate For microprocessor relays: • Verify operation of the relay inputs and outputs that are essential to proper functioning of the Protection System. • Verify acceptable measurement of power system input values.
Monitored microprocessor protective relay with the following: • Internal self-diagnosis and alarming (see Table 2). • Voltage and/or current waveform sampling three or more times per power cycle, and conversion of samples to numeric values for measurement calculations by microprocessor electronics. • Alarming for power supply failure (see Table 2).	12 Calendar Years	Verify: • Settings are as specified. • Operation of the relay inputs and outputs that are essential to proper functioning of the Protection System. • Acceptable measurement of power system input values.

[2] For the tables in this standard, a calendar year starts on the first day of a new year (January 1) after a maintenance activity has been completed.
For the tables in this standard, a calendar month starts on the first day of the first month after a maintenance activity has been completed.

Table 1-1 Component Type - Protective Relay Excluding distributed UFLS and distributed UVLS (see Table 3)		
Component Attributes	**Maximum Maintenance Interval[2]**	**Maintenance Activities**
Monitored microprocessor protective relay with preceding row attributes and the following: • Ac measurements are continuously verified by comparison to an independent ac measurement source, with alarming for excessive error (See Table 2). • Some or all binary or status inputs and control outputs are monitored by a process that continuously demonstrates ability to perform as designed, with alarming for failure (See Table 2). • Alarming for change of settings (See Table 2).	12 Calendar Years	Verify only the unmonitored relay inputs and outputs that are essential to proper functioning of the Protection System.

Table 1-2 Component Type - Communications Systems Excluding distributed UFLS and distributed UVLS (see Table 3)		
Component Attributes	**Maximum Maintenance Interval**	**Maintenance Activities**
Any unmonitored communications system necessary for correct operation of protective functions, and not having all the monitoring attributes of a category below.	4 Calendar Months	Verify that the communications system is functional.
	6 Calendar Years	Verify that the communications system meets performance criteria pertinent to the communications technology applied (e.g. signal level, reflected power, or data error rate). Verify operation of communications system inputs and outputs that are essential to proper functioning of the Protection System.
Any communications system with continuous monitoring or periodic automated testing for the presence of the channel function, and alarming for loss of function (See Table 2).	12 Calendar Years	Verify that the communications system meets performance criteria pertinent to the communications technology applied (e.g. signal level, reflected power, or data error rate). Verify operation of communications system inputs and outputs that are essential to proper functioning of the Protection System.
Any communications system with all of the following: • Continuous monitoring or periodic automated testing for the performance of the channel using criteria pertinent to the communications technology applied (e.g. signal level, reflected power, or data error rate, and alarming for excessive performance degradation). (See Table 2) • Some or all binary or status inputs and control outputs are monitored by a process that continuously demonstrates ability to perform as designed, with alarming for failure (See Table 2).	12 Calendar Years	Verify only the unmonitored communications system inputs and outputs that are essential to proper functioning of the Protection System

Table 1-3 Component Type - Voltage and Current Sensing Devices Providing Inputs to Protective Relays Excluding distributed UFLS and distributed UVLS (see Table 3)		
Component Attributes	**Maximum Maintenance Interval**	**Maintenance Activities**
Any voltage and current sensing devices not having monitoring attributes of the category below.	12 Calendar Years	Verify that current and voltage signal values are provided to the protective relays.
Voltage and Current Sensing devices connected to microprocessor relays with AC measurements are continuously verified by comparison of sensing input value, as measured by the microprocessor relay, to an independent ac measurement source, with alarming for unacceptable error or failure (see Table 2).	No periodic maintenance specified	None.

<table>
<tr><th colspan="3">Table 1-4(a)
Component Type – Protection System Station dc Supply Using Vented Lead-Acid (VLA) Batteries
Excluding distributed UFLS and distributed UVLS (see Table 3)

Protection System Station dc supply used only for non-BES interrupting devices for SPS, non-distributed UFLS systems, or non-distributed UVLS systems is excluded (see Table 1-4(e)).</th></tr>
<tr><th>Component Attributes</th><th>Maximum Maintenance Interval</th><th>Maintenance Activities</th></tr>
<tr><td rowspan="2">Protection System Station dc supply using Vented Lead-Acid (VLA) batteries not having monitoring attributes of Table 1-4(f).</td><td>4 Calendar Months</td><td>Verify:
• Station dc supply voltage
Inspect:
• Electrolyte level
• For unintentional grounds</td></tr>
<tr><td>18 Calendar Months</td><td>Verify:
• Float voltage of battery charger
• Battery continuity
• Battery terminal connection resistance
• Battery intercell or unit-to-unit connection resistance
Inspect:
• Cell condition of all individual battery cells where cells are visible – or measure battery cell/unit internal ohmic values where the cells are not visible
• Physical condition of battery rack</td></tr>
</table>

Table 1-4(a)

Component Type – Protection System Station dc Supply Using Vented Lead-Acid (VLA) Batteries
Excluding distributed UFLS and distributed UVLS (see Table 3)

Protection System Station dc supply used only for non-BES interrupting devices for SPS, non-distributed UFLS systems, or non-distributed UVLS systems is excluded (see Table 1-4(e)).

Component Attributes	Maximum Maintenance Interval	Maintenance Activities
	18 Calendar Months -or- 6 Calendar Years	Verify that the station battery can perform as manufactured by evaluating cell/unit measurements indicative of battery performance (e.g. internal ohmic values or float current) against the station battery baseline. -or- Verify that the station battery can perform as manufactured by conducting a performance or modified performance capacity test of the entire battery bank.

Table 1-4(b) Component Type – Protection System Station dc Supply Using Valve-Regulated Lead-Acid (VRLA) Batteries Excluding distributed UFLS and distributed UVLS (see Table 3) Protection System Station dc supply used only for non-BES interrupting devices for SPS, non-distributed UFLS systems, or non-distributed UVLS systems is excluded (see Table 1-4(e)).		
Component Attributes	**Maximum Maintenance Interval**	**Maintenance Activities**
Protection System Station dc supply **with Valve Regulated Lead-Acid (VRLA) batteries** not having monitoring attributes of Table 1-4(f).	4 Calendar Months	Verify: • Station dc supply voltage Inspect: • For unintentional grounds
	6 Calendar Months	Inspect: • Condition of all individual units by measuring battery cell/unit internal ohmic values.
	18 Calendar Months	Verify: • Float voltage of battery charger • Battery continuity • Battery terminal connection resistance • Battery intercell or unit-to-unit connection resistance Inspect: • Physical condition of battery rack

Table 1-4(b) Component Type – Protection System Station dc Supply Using Valve-Regulated Lead-Acid (VRLA) Batteries Excluding distributed UFLS and distributed UVLS (see Table 3) Protection System Station dc supply used only for non-BES interrupting devices for SPS, non-distributed UFLS systems, or non-distributed UVLS systems is excluded (see Table 1-4(e)).		
Component Attributes	**Maximum Maintenance Interval**	**Maintenance Activities**
	6 Calendar Months -or- 3 Calendar Years	Verify that the station battery can perform as manufactured by evaluating cell/unit measurements indicative of battery performance (e.g. internal ohmic values or float current) against the station battery baseline. -or- Verify that the station battery can perform as manufactured by conducting a performance or modified performance capacity test of the entire battery bank.

Table 1-4(c) Component Type – Protection System Station dc Supply Using Nickel-Cadmium (NiCad) Batteries Excluding distributed UFLS and distributed UVLS (see Table 3) Protection System Station dc supply used only for non-BES interrupting devices for SPS, non-distributed UFLS system, or non-distributed UVLS systems is excluded (see Table 1-4(e)).		
Component Attributes	**Maximum Maintenance Interval**	**Maintenance Activities**
Protection System Station dc supply **Nickel-Cadmium (NiCad) batteries** not having monitoring attributes of Table 1-4(f).	4 Calendar Months	Verify: • Station dc supply voltage Inspect: • Electrolyte level • For unintentional grounds
	18 Calendar Months	Verify: • Float voltage of battery charger • Battery continuity • Battery terminal connection resistance • Battery intercell or unit-to-unit connection resistance Inspect: • Cell condition of all individual battery cells. • Physical condition of battery rack

Table 1-4(c) Component Type – Protection System Station dc Supply Using Nickel-Cadmium (NiCad) Batteries Excluding distributed UFLS and distributed UVLS (see Table 3) Protection System Station dc supply used only for non-BES interrupting devices for SPS, non-distributed UFLS system, or non-distributed UVLS systems is excluded (see Table 1-4(e)).		
Component Attributes	Maximum Maintenance Interval	Maintenance Activities
	6 Calendar Years	Verify that the station battery can perform as manufactured by conducting a performance or modified performance capacity test of the entire battery bank.

Table 1-4(d)

Component Type – Protection System Station dc Supply Using Non Battery Based Energy Storage

Excluding distributed UFLS and distributed UVLS (see Table 3)

Protection System Station dc supply used only for non-BES interrupting devices for SPS, non-distributed UFLS system, or non-distributed UVLS systems is excluded (see Table 1-4(e)).

Component Attributes	Maximum Maintenance Interval	Maintenance Activities
Any Protection System station dc supply not using a battery and not having monitoring attributes of Table 1-4(f).	4 Calendar Months	Verify: • Station dc supply voltage Inspect: • For unintentional grounds
	18 Calendar Months	Inspect: Condition of non-battery based dc supply
	6 Calendar Years	Verify that the dc supply can perform as manufactured when ac power is not present.

Table 1-4(e) Component Type – Protection System Station dc Supply for non-BES Interrupting Devices for SPS, non-distributed UFLS, and non-distributed UVLS systems		
Component Attributes	**Maximum Maintenance Interval**	**Maintenance Activities**
Any Protection System dc supply used for tripping only non-BES interrupting devices as part of a SPS, non-distributed UFLS, or non-distributed UVLS system and not having monitoring attributes of Table 1-4(f).	When control circuits are verified (See Table 1-5)	Verify Station dc supply voltage.

Table 1-4(f) Exclusions for Protection System Station dc Supply Monitoring Devices and Systems		
Component Attributes	**Maximum Maintenance Interval**	**Maintenance Activities**
Any station dc supply with high and low voltage monitoring and alarming of the battery charger voltage to detect charger overvoltage and charger failure (See Table 2).	No periodic maintenance specified	No periodic verification of station dc supply voltage is required.
Any battery based station dc supply with electrolyte level monitoring and alarming in every cell (See Table 2).		No periodic inspection of the electrolyte level for each cell is required.
Any station dc supply with unintentional dc ground monitoring and alarming (See Table 2).		No periodic inspection of unintentional dc grounds is required.
Any station dc supply with charger float voltage monitoring and alarming to ensure correct float voltage is being applied on the station dc supply (See Table 2).		No periodic verification of float voltage of battery charger is required.
Any battery based station dc supply with monitoring and alarming of battery string continuity (See Table 2).		No periodic verification of the battery continuity is required.
Any battery based station dc supply with monitoring and alarming of the intercell and/or terminal connection detail resistance of the entire battery (See Table 2).		No periodic verification of the intercell and terminal connection resistance is required.
Any Valve Regulated Lead-Acid (VRLA) or Vented Lead-Acid (VLA) station battery with internal ohmic value or float current monitoring and alarming, and evaluating present values relative to baseline internal ohmic values for every cell/unit (See Table 2).		No periodic evaluation relative to baseline of battery cell/unit measurements indicative of battery performance is required to verify the station battery can perform as manufactured.
Any Valve Regulated Lead-Acid (VRLA) or Vented Lead-Acid (VLA) station battery with monitoring and alarming of each cell/unit internal ohmic value (See Table 2).		No periodic inspection of the condition of all individual units by measuring battery cell/unit internal ohmic values of a station VRLA or Vented Lead-Acid (VLA) battery is required.

Table 1-5 Component Type - Control Circuitry Associated With Protective Functions Excluding distributed UFLS and distributed UVLS (see Table 3) Note: Table requirements apply to all Control Circuitry Components of Protection Systems, and SPSs except as noted.		
Component Attributes	**Maximum Maintenance Interval**	**Maintenance Activities**
Trip coils or actuators of circuit breakers, interrupting devices, or mitigating devices (regardless of any monitoring of the control circuitry).	6 Calendar Years	Verify that each trip coil is able to operate the circuit breaker, interrupting device, or mitigating device.
Electromechanical lockout devices which are directly in a trip path from the protective relay to the interrupting device trip coil (regardless of any monitoring of the control circuitry).	6 Calendar Years	Verify electrical operation of electromechanical lockout devices.
Unmonitored control circuitry associated with SPS. (See Table 4-2(b) for SPS which include Automatic Reclosing.)	12 Calendar Years	Verify all paths of the control circuits essential for proper operation of the SPS.
Unmonitored control circuitry associated with protective functions inclusive of all auxiliary relays.	12 Calendar Years	Verify all paths of the trip circuits inclusive of all auxiliary relays through the trip coil(s) of the circuit breakers or other interrupting devices.
Control circuitry associated with protective functions and/or SPSs whose integrity is monitored and alarmed (See Table 2).	No periodic maintenance specified	None.

Table 2 – Alarming Paths and Monitoring In Tables 1-1 through 1-5, Table 3, and Tables 4-1 through 4-2, alarm attributes used to justify extended maximum maintenance intervals and/or reduced maintenance activities are subject to the following maintenance requirements		
Component Attributes	**Maximum Maintenance Interval**	**Maintenance Activities**
Any alarm path through which alarms in Tables 1-1 through 1-5, Table 3, and Tables 4-1 through 4-2 are conveyed from the alarm origin to the location where corrective action can be initiated, and not having all the attributes of the "Alarm Path with monitoring" category below. Alarms are reported within 24 hours of detection to a location where corrective action can be initiated.	12 Calendar Years	Verify that the alarm path conveys alarm signals to a location where corrective action can be initiated.
Alarm Path with monitoring: The location where corrective action is taken receives an alarm within 24 hours for failure of any portion of the alarming path from the alarm origin to the location where corrective action can be initiated.	No periodic maintenance specified	None.

Table 3

Maintenance Activities and Intervals for distributed UFLS and distributed UVLS Systems

Component Attributes	Maximum Maintenance Interval	Maintenance Activities
Any unmonitored protective relay not having all the monitoring attributes of a category below.	6 Calendar Years	Verify that settings are as specified. For non-microprocessor relays: • Test and, if necessary calibrate. For microprocessor relays: • Verify operation of the relay inputs and outputs that are essential to proper functioning of the Protection System. • Verify acceptable measurement of power system input values.
Monitored microprocessor protective relay with the following: • Internal self-diagnosis and alarming (See Table 2). • Voltage and/or current waveform sampling three or more times per power cycle, and conversion of samples to numeric values for measurement calculations by microprocessor electronics. Alarming for power supply failure (See Table 2).	12 Calendar Years	Verify: • Settings are as specified. • Operation of the relay inputs and outputs that are essential to proper functioning of the Protection System. • Acceptable measurement of power system input values
Monitored microprocessor protective relay with preceding row attributes and the following: • Ac measurements are continuously verified by comparison to an independent ac measurement source, with alarming for excessive error (See Table 2).	12 Calendar Years	Verify only the unmonitored relay inputs and outputs that are essential to proper functioning of the Protection System.

Table 3 Maintenance Activities and Intervals for distributed UFLS and distributed UVLS Systems		
Component Attributes	**Maximum Maintenance Interval**	**Maintenance Activities**
• Some or all binary or status inputs and control outputs are monitored by a process that continuously demonstrates ability to perform as designed, with alarming for failure (See Table 2). Alarming for change of settings (See Table 2).		
Voltage and/or current sensing devices associated with UFLS or UVLS systems.	12 Calendar Years	Verify that current and/or voltage signal values are provided to the protective relays.
Protection System dc supply for tripping non-BES interrupting devices used only for a UFLS or UVLS system.	12 Calendar Years	Verify Protection System dc supply voltage.
Control circuitry between the UFLS or UVLS relays and electromechanical lockout and/or tripping auxiliary devices (excludes non-BES interrupting device trip coils).	12 Calendar Years	Verify the path from the relay to the lockout and/or tripping auxiliary relay (including essential supervisory logic).
Electromechanical lockout and/or tripping auxiliary devices associated only with UFLS or UVLS systems (excludes non-BES interrupting device trip coils).	12 Calendar Years	Verify electrical operation of electromechanical lockout and/or tripping auxiliary devices.
Control circuitry between the electromechanical lockout and/or tripping auxiliary devices and the non-BES interrupting devices in UFLS or UVLS systems, or between UFLS or UVLS relays (with no interposing electromechanical lockout or auxiliary device) and the non-BES interrupting devices (excludes non-BES interrupting device trip coils).	No periodic maintenance specified	None.
Trip coils of non-BES interrupting devices in UFLS or UVLS systems.	No periodic maintenance specified	None.

Table 4-1 Maintenance Activities and Intervals for Automatic Reclosing Components Component Type – Reclosing Relay		
Component Attributes	**Maximum Maintenance Interval**	**Maintenance Activities**
Any unmonitored reclosing relay not having all the monitoring attributes of a category below.	6 Calendar Years	Verify that settings are as specified. For non-microprocessor relays: • Test and, if necessary calibrate For microprocessor relays: • Verify operation of the relay inputs and outputs that are essential to proper functioning of the Automatic Reclosing.
Monitored microprocessor reclosing relay with the following: • Internal self-diagnosis and alarming (See Table 2). • Alarming for power supply failure (See Table 2).	12 Calendar Years	Verify: • Settings are as specified. • Operation of the relay inputs and outputs that are essential to proper functioning of the Automatic Reclosing.

Table 4-2(a) Maintenance Activities and Intervals for Automatic Reclosing Components Component Type – Control Circuitry Associated with Reclosing Relays that are NOT an Integral Part of an SPS		
Component Attributes	**Maximum Maintenance Interval**	**Maintenance Activities**
Unmonitored Control circuitry associated with Automatic Reclosing that is not an integral part of an SPS.	12 Calendar Years	Verify that Automatic Reclosing, upon initiation, does not issue a premature closing command to the close circuitry.
Control circuitry associated with Automatic Reclosing that is not part of an SPS and is monitored and alarmed for conditions that would result in a premature closing command. (See Table 2)	No periodic maintenance specified	None.

Table 4-2(b) Maintenance Activities and Intervals for Automatic Reclosing Components Component Type – Control Circuitry Associated with Reclosing Relays that ARE an Integral Part of an SPS		
Component Attributes	**Maximum Maintenance Interval**	**Maintenance Activities**
Close coils or actuators of circuit breakers or similar devices that are used in conjunction with Automatic Reclosing as part of an SPS (regardless of any monitoring of the control circuitry).	6 Calendar Years	Verify that each close coil or actuator is able to operate the circuit breaker or mitigating device.
Unmonitored close control circuitry associated with Automatic Reclosing used as an integral part of an SPS.	12 Calendar Years	Verify all paths of the control circuits associated with Automatic Reclosing that are essential for proper operation of the SPS.
Control circuitry associated with Automatic Reclosing that is an integral part of an SPS whose integrity is monitored and alarmed. (See Table 2)	No periodic maintenance specified	None.

Table 5

Maintenance Activities and Intervals for Sudden Pressure Relaying

Component Attributes	Maximum Maintenance Interval	Maintenance Activities
Any fault pressure relay.	6 Calendar Years	Verify the pressure or flow sensing mechanism is operable.
Control circuitry associated with Sudden Pressure Relaying from the fault pressure relay to the interrupting device trip coil(s).	12 Calendar Years	Verify all paths of the control circuits that are essential for proper operation of the Sudden Pressure Relaying.

PRC-005 — Attachment A

Criteria for a Performance-Based Protection System Maintenance Program

Purpose: To establish a technical basis for initial and continued use of a performance-based Protection System Maintenance Program (PSMP).

To establish the technical justification for the initial use of a performance-based PSMP:

1. Develop a list with a description of Components included in each designated Segment, with a minimum **Segment** population of 60 Components.
2. Maintain the Components in each Segment according to the time-based maximum allowable intervals established in Tables 1-1 through 1-5, Table 3, Tables 4-1 through 4-2, and Table 5 until results of maintenance activities for the Segment are available for a minimum of 30 individual Components of the Segment.
3. Document the maintenance program activities and results for each Segment, including maintenance dates and Countable Events for each included Component.
4. Analyze the maintenance program activities and results for each Segment to determine the overall performance of the Segment and develop maintenance intervals.
5. Determine the maximum allowable maintenance interval for each Segment such that the Segment experiences **Countable Events** on no more than 4% of the Components within the Segment, for the greater of either the last 30 Components maintained or all Components maintained in the previous year.

To maintain the technical justification for the ongoing use of a performance-based PSMP:

1. At least annually, update the list of Components and Segments and/or description if any changes occur within the Segment.
2. Perform maintenance on the greater of 5% of the Components (addressed in the performance based PSMP) in each Segment or 3 individual Components within the Segment in each year.
3. For the prior year, analyze the maintenance program activities and results for each Segment to determine the overall performance of the Segment.
4. Using the prior year's data, determine the maximum allowable maintenance interval for each Segment such that the Segment experiences Countable Events on no more than 4% of the Components within the Segment, for the greater of either the last 30 Components maintained or all Components maintained in the previous year.

If the Components in a Segment maintained through a performance-based PSMP experience 4% or more Countable Events, develop, document, and implement an action plan to reduce the Countable Events to less than 4% of the Segment population within 3 years.

Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Development Steps Completed

1. SAR posted for comment February 13, 2014 – March 14, 2014.

Description of Current Draft

The Protection System Maintenance and Testing Standard Drafting Team (PSMT SDT) is posting draft 1 of PRC-005-X for a 45-day comment period and ballot in the last ten days of the comment period under the new Standards Process Manual (Effective: June 26, 2013).

This draft contains the technical content of the standard. A parallel effort in the Project 2014-01, Standards Applicability for Dispersed Generation Resources, will post an applicability change to PRC-005-2 and PRC-005-3 for comment and ballot.

Anticipated Actions	Anticipated Date
45-day Formal Comment Period with Parallel Ballot	April 17 – June 2, 2014
45-day Additional Formal Comment Period with Parallel Ballot (if necessary)	July 21, – September 3, 2014
Final ballot	September 15, 2014
BOT adoption	November 2014

Definitions of Terms Used in Standard

This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the Reliability Standards Glossary of Terms (Glossary) are not repeated here. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, this defined term will be removed from the individual standard and added to the Glossary.

Protection System Maintenance Program (PSMP) — An ongoing program by which Protection System, Automatic Reclosing, and Sudden Pressure Relaying ~~c~~Components are kept in working order and proper operation of malfunctioning components is restored. A maintenance program for a specific ~~c~~Component includes one or more of the following activities:

- Verify — Determine that the ~~c~~Component is functioning correctly.
- Monitor — Observe the routine in-service operation of the ~~c~~Component.
- Test — Apply signals to a ~~c~~Component to observe functional performance or output behavior, or to diagnose problems.
- Inspect — Examine for signs of ~~c~~Component failure, reduced performance or degradation.
- Calibrate — Adjust the operating threshold or measurement accuracy of a measuring element to meet the intended performance requirement.

See Section A.6, Definitions Used in this Standard, for additional definitions that are new or modified for use within this standard.

When this standard has received ballot approval, the text boxes will be moved to the Application Guidelines Section of the Standard.

A. Introduction

1. **Title:** **Protection System, ~~and~~ Automatic Reclosing, and Sudden Pressure Relaying Maintenance**
2. **Number:** **PRC-005-X~~3~~**
3. **Purpose:** To document and implement programs for the maintenance of all Protection Systems, ~~and~~ Automatic Reclosing, and Sudden Pressure Relaying affecting the reliability of the Bulk Electric System (BES) so that they are kept in working order.

Rationale for Applicability Section: This section does not reflect the applicability changes that will be proposed by the Project 2014-01 Standards Applicability for Dispersed Generation Resources standards drafting team.

4. **Applicability:**

   4.1. Functional Entities:

   4.1.1 Transmission Owner

   4.1.2 Generator Owner

   4.1.3 Distribution Provider

   4.1.4 Balancing Authority

   4.2. Facilities:

   4.2.1 Protection Systems and Sudden Pressure Relaying that are installed for the purpose of detecting Faults on BES Elements (lines, buses, transformers, etc.)

   4.2.2 Protection Systems used for underfrequency load-shedding systems installed per ERO underfrequency load-shedding requirements.

   4.2.3 Protection Systems used for undervoltage load-shedding systems installed to prevent system voltage collapse or voltage instability for BES reliability.

   4.2.4 Protection Systems installed as a Special Protection System (SPS) for BES reliability.

   4.2.5 Protection Systems for generator Facilities that are part of the BES, including:

   4.2.5.1 Protection Systems that act to trip the generator either directly or via lockout or auxiliary tripping relays.

4.2.5.2 Protection Systems and Sudden Pressure Relaying for generator step-up transformers for generators that are part of the BES.

4.2.5.3 Protection Systems for transformers connecting aggregated generation, where the aggregated generation is part of the BES (e.g., transformers connecting facilities such as wind-farms to the BES).

4.2.5.4 Protection Systems and Sudden Pressure Relaying for station service or excitation transformers connected to the generator bus of generators which are part of the BES, that act to trip the generator either directly or via lockout or tripping auxiliary relays.

4.2.6 Automatic Reclosing[1], including:

4.2.6.1 Automatic Reclosing applied on the terminals of Elements connected to the BES bus located at generating plant substations where the total installed gross generating plant capacity is greater than the gross capacity of the largest BES generating unit within the Balancing Authority Area.

4.2.6.2 Automatic Reclosing applied on the terminals of all BES Elements at substations one bus away from generating plants specified in Section 4.2.6.1 when the substation is less than 10 circuit-miles from the generating plant substation.

~~**4.2.6.3**~~ **4.2.6.3.** Automatic Reclosing applied as an integral part of an SPS specified in Section 4.2.4.

5. **Effective Date:** See Implementation Plan

~~6. **Background:**~~

~~7.~~6. **Definitions Used in this Standard:** ~~The following terms are defined for use only within PRC-005-3, and should remain with the standard upon approval rather than begin moved to the Glossary of Terms.~~

Automatic Reclosing – Includes the following Components:

- Reclosing relay
- Control circuitry associated with the reclosing relay.

[1] Automatic Reclosing addressed in Section 4.2.7~~6~~.1 and 4.2.7~~6~~.2 may be excluded if the equipment owner can demonstrate that a close-in three-phase fault present for twice the normal clearing time (capturing a minimum trip-close-trip time delay) does not result in a total loss of gross generation in the Interconnection exceeding the gross capacity of the largest BES generating unit within the Balancing Authority Area where the Automatic Reclosing is applied.

Sudden Pressure Relaying – A system that trips an interrupting device(s) to isolate the equipment it is monitoring and includes the following Components:

- Fault pressure relay – a mechanical relay or device that detects rapid changes in gas pressure, oil pressure, or oil flow that are indicative of Faults within liquid-filled, wire-wound equipment
- Control circuitry associated with a fault pressure relay

Unresolved Maintenance Issue – A deficiency identified during a maintenance activity that causes the Component~~component~~ to not meet the intended performance, cannot be corrected during the maintenance interval, and requires follow-up corrective action.

Segment – Components of a consistent design standard, or a particular model or type from a single manufacturer that typically share other common elements. Consistent performance is expected across the entire population of a Segment. A Segment must contain at least sixty (60) individual Components.

Component Type –

- Any~~Either any~~ one of the five specific elements of a~~the~~ Protection System.
- Any one of the two specific elements of Automatic Reclosing.
- Any ~~definition or any~~ one of the two specific elements of Sudden Pressure Relaying~~the Automatic Reclosing definition~~.

Rationale for the deletion of part of the definition of Component: The SDT determined that it was explanatory in nature and adequately addressed in the Supplementary Reference and FAQ Document.

Component – Any individual discrete piece of equipment included in a Protection System, Automatic Reclosing, or Sudden Pressure Relaying.

~~**Component** – A Component is any individual discrete piece of equipment included in a Protection System or in Automatic Reclosing, including but not limited to a protective relay, reclosing relay, or current sensing device. The designation of what constitutes a control circuit Component is dependent upon how an entity performs and tracks the testing of the control circuitry. Some entities test their control circuits on a breaker basis whereas others test their circuitry on a local zone of protection basis. Thus, entities are allowed the latitude to designate their own definitions of control circuit Components. Another example of where the entity has some discretion on determining what constitutes a single Component is the voltage and current sensing devices, where the entity may choose either to designate a full three-phase set of such devices or a single device as a single Component.~~

Countable Event – A failure of a Component requiring repair or replacement, any condition discovered during the maintenance activities in Tables 1-1 through 1-5, Table 3, ~~and~~ Tables 4-1 through 4-2, and Table 5, which requires corrective action or a Protection System Misoperation attributed to hardware failure or calibration failure. Misoperations due to product design errors, software errors, relay settings different from specified settings, Protection System Component, ~~or~~ Automatic Reclosing, or Sudden Pressure Relaying configuration or application errors are not included in Countable Events.

B. Requirements and Measures

R1. Each Transmission Owner, Generator Owner, and Distribution Provider shall establish a Protection System Maintenance Program (PSMP) for its Protection Systems, ~~and~~ Automatic Reclosing, and Sudden Pressure Relaying identified in ~~Facilities~~ Section 4.2, Facilities. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

The PSMP shall:

1.1. Identify which maintenance method (time-based, performance-based per PRC-005 Attachment A, or a combination) is used to address each Protection System, ~~and~~ Automatic Reclosing, and Sudden Pressure Relaying Component Type. All batteries associated with the station dc supply Component Type of a Protection System shall be included in a time-based program as described in Table 1-4 and Table 3.

1.2. Include the applicable monitored Component attributes applied to each Protection System, ~~and~~ Automatic Reclosing, and Sudden Pressure Relaying Component Type consistent with the maintenance intervals specified in Tables 1-1 through 1-5, Table 2, Table 3, ~~and~~ Table 4-1 through 4-2, and Table 5 where monitoring is used to extend the maintenance intervals beyond those specified for unmonitored Protection System, ~~and~~ Automatic Reclosing, and Sudden Pressure Relaying Components.

M1. Each Transmission Owner, Generator Owner and Distribution Provider shall have a documented Protection System Maintenance Program in accordance with Requirement R1.

For each Protection System, ~~and~~ Automatic Reclosing, and Sudden Pressure Relaying Component Type, the documentation shall include the type of maintenance method applied (time-based, performance-based, or a combination of these maintenance methods), and shall include all batteries associated with the station dc supply Component Types in a time-based program as described in Table 1-4 and Table 3. (Part 1.1)

For Component Types that use monitoring to extend the maintenance intervals, the responsible entity(s) shall have evidence for each Protection System, ~~and~~ Automatic Reclosing, and Sudden Pressure Relaying Component Type (such as manufacturer's specifications or engineering drawings) of the appropriate monitored Component attributes as specified in Tables 1-1 through 1-5, Table 2, Table 3, ~~and~~ Table 4-1 through 4-2, and Table 5. (Part 1.2)

R2. Each Transmission Owner, Generator Owner, and Distribution Provider that uses performance-based maintenance intervals in its PSMP shall follow the procedure established in PRC-005 Attachment A to establish and maintain its performance-based intervals. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

M2. Each Transmission Owner, Generator Owner, and Distribution Provider that uses performance-based maintenance intervals shall have evidence that its current performance-based maintenance program(s) is in accordance with Requirement R2, which may include, but is not limited to, Component lists, dated maintenance records, and dated analysis records and results.

Rationale for R3 part 3.1 and 3.1.1.: The SDT, upon further reflection, determined that the PRC-005-3 Implementation Plan actually included a requirement that entities with newly-identified Automatic Reclosing Components implement its PSMP for those Components, and therefore determined that it was more appropriate to include this information in the standard rather than the implementation plan.

R3. Each Transmission Owner, Generator Owner, and Distribution Provider that utilizes time-based maintenance program(s) shall, except as provided in part 3.1, maintain its Protection System, ~~and~~ Automatic Reclosing, and Sudden Pressure Relaying Components that are included within the time-based maintenance program in accordance with the minimum maintenance activities and maximum maintenance intervals prescribed within Tables 1-1 through 1-5, Table 2, Table 3, ~~and~~ Table 4-1 through 4-2, and Table 5. *[Violation Risk Factor: High] [Time Horizon: Operations Planning]*

3.1. For each newly-identified Automatic Reclosing Component following a notification under Requirement R6, each Transmission Owner, Generator Owner, and Distribution Provider shall perform maintenance activities or provide documentation of prior maintenance activities according to either 3.1.1 or 3.1.2.

3.1.1. Complete the maintenance activities prescribed within Tables 4-1, 4-2(a), and 4-2(b) for the newly-identified Automatic Reclosing Component prior to the end of the third calendar year following the notification under Requirement R6; or

3.1.2. Provide documentation that the Automatic Reclosing Component was last maintained in accordance with the minimum maintenance activities and maximum maintenance intervals prescribed within Tables 4-1, 4-2(a), and 4-2(b).

M3. Each Transmission Owner, Generator Owner, and Distribution Provider that utilizes time-based maintenance program(s) shall have evidence that it has maintained its

Protection System, ~~and~~ Automatic Reclosing, and Sudden Pressure Relaying Components included within its time-based program in accordance with Requirement R3. The evidence may include, but is not limited to, dated maintenance records, dated maintenance summaries, dated check-off lists, dated inspection records, or dated work orders.

Rationale for R4 part 4.1 and 4.1.1.: The SDT, upon further reflection, determined that the PRC-005-3 Implementation Plan actually included a requirement that entities with newly-identified Automatic Reclosing Components implement its PSMP for those Components, and therefore determined that it was more appropriate to include this information in the standard rather than the implementation plan.

R4. Each Transmission Owner, Generator Owner, and Distribution Provider that utilizes performance-based maintenance program(s) in accordance with Requirement R2 shall, except as provided in part 4.1, implement and follow its PSMP for its Protection System, ~~and~~ Automatic Reclosing, and Sudden Pressure Relaying Components that are included within the performance-based program(s). *[Violation Risk Factor: High] [Time Horizon: Operations Planning]*

4.1. For each newly-identified Automatic Reclosing Component following a notification under Requirement R6, each Transmission Owner, Generator Owner, and Distribution Provider shall perform maintenance activities or provide documentation of prior maintenance activities according to either 4.1.1 or 4.1.2.

4.1.1. Complete the maintenance activities prescribed within Tables 4-1, 4-2(a), and 4-2(b) for the newly-identified Automatic Reclosing Component prior to the end of the third calendar year following the notification under Requirement R6; or

4.1.2. Provide documentation that the Automatic Reclosing Component was last maintained in accordance with the minimum maintenance activities and maximum maintenance intervals prescribed within Tables 4-1, 4-2(a), and 4-2(b).

M4. Each Transmission Owner, Generator Owner, and Distribution Provider that utilizes performance-based maintenance intervals in accordance with Requirement R2 shall have evidence that it has implemented the Protection System Maintenance Program for the Protection System, ~~and~~ Automatic Reclosing, and Sudden Pressure Relaying Components included in its performance-based program in accordance with Requirement R4. The evidence may include, but is not limited to, dated maintenance records, dated maintenance summaries, dated check-off lists, dated inspection records, or dated work orders.

R5. Each Transmission Owner, Generator Owner, and Distribution Provider shall demonstrate efforts to correct identified Unresolved Maintenance Issues. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

M5. Each Transmission Owner, Generator Owner, and Distribution Provider shall have evidence that it has undertaken efforts to correct identified Unresolved Maintenance Issues in accordance with Requirement R5. The evidence may include, but is not limited to, work orders, replacement Component orders, invoices, project schedules with completed milestones, return material authorizations (RMAs) or purchase orders.

Rationale for R6: The information addressed in Requirement R6 is necessary for Transmission Owners, Generator Owners, and Distribution Provides to accurately apply Section 4.2.7, Applicability. The Balancing Authority is the entity that maintains the information and should have the responsibility to provide this information to the applicable entities. The drafting team reconsidered the inclusion of the Balancing Authority and determined it is appropriate to include the requirement the standard. This requirement may be relocated to another standard during future reviews of standards for quality and content.

The periodicity was chosen to balance the needs of the Transmission Owner, Generator Owner, and Distribution Provider to obtain the information with the needs of the Balancing Authority to provide an accurate gross capacity (considering retirement or installation of generating units and/or changes in its Balancing Authority Area) in order to properly include Automatic Reclosing in a PSMP.

R6. Each Balancing Authority shall, at least once every calendar year with not more than 15 calendar months between notifications, notify each Transmission Owner, Generator Owner, and Distribution Provider within its Balancing Authority Area of the gross capacity, in MW or MVA, of the largest BES generating unit within the Balancing Authority Area. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

M6. Each Balancing Authority shall have dated documentation that it notified each Transmission Owner, Generator Owner, and Distribution Provider in accordance with Requirement R6. Examples of evidence may include, but are not limited to, copies of correspondence, such as e-mails or memoranda.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

As defined in the NERC Rules of Procedure, "Compliance Enforcement Authority" means NERC or the Regional Entity in their respective roles of monitoring and enforcing compliance with the NERC Reliability Standards.

1.2. Evidence Retention

The following evidence retention periods identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

The Transmission Owner, Generator Owner, ~~and~~ Distribution Provider, and Balancing Authority shall each keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

For Requirement R1, the Transmission Owner, Generator Owner, and Distribution Provider shall each keep its current dated Protection System Maintenance Program, as well as any superseded versions since the preceding compliance audit, including the documentation that specifies the type of maintenance program applied for each Protection System Component Type.

For Requirement R2, Requirement R3, Requirement R4, and Requirement R5, the Transmission Owner, Generator Owner, and Distribution Provider shall each keep documentation of the ~~two~~ most recent performance~~performances~~ of each distinct maintenance activity for the Protection System, ~~or~~ Automatic Reclosing, or Sudden Pressure Relaying Component, or all performances of each distinct maintenance activity for the Protection System, ~~or~~ Automatic Reclosing, or Sudden Pressure Relaying Component since the previous scheduled audit date, whichever is longer.

For Requirement R6, the Balancing Authority shall keep documentation for three calendar years that it provided information identifying the largest BES generating unit to the Transmission Owners, Generator Owners, and Distribution Providers in its Balancing Authority Area.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.3. Compliance Monitoring and Assessment Processes:

Compliance Audits

Self-Certifications

Spot Checking

Compliance Violation Investigations

Self-Reporting

Complaints

1.4. Additional Compliance Information

None

Table of Compliance Elements

Requirement Number	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	The ~~responsible~~ entity's PSMP failed to specify whether one Component Type is being addressed by time-based or performance-based maintenance, or a combination of both (part ~~. (Part~~ 1.1). ~~)~~ ~~OR~~ ~~The responsible entity's PSMP failed to include applicable station batteries in a time-based program. (Part 1.1)~~	The ~~responsible~~ entity's PSMP failed to specify whether two Component Types are being addressed by time-based or performance-based maintenance, or a combination of both (part ~~. (Part~~ 1.1). ~~)~~	The ~~responsible~~ entity's PSMP failed to specify whether three Component Types are being addressed by time-based or performance-based maintenance, or a combination of both. (part ~~Part~~ 1.1). OR The ~~responsible~~ entity's PSMP failed to include the applicable monitoring attributes applied to each Component Type consistent with the maintenance intervals specified in Tables 1-1 through 1-5, Table 2, Table 3, ~~and~~ Tables 4-1 through 4-2, and Table 5 where monitoring is used to extend the maintenance intervals beyond those specified for unmonitored Components (part ~~. (Part~~ 1.2).	The ~~responsible~~ entity failed to establish a PSMP. OR The ~~responsible~~ entity's PSMP failed to specify whether four or more Component Types are being addressed by time-based or performance-based maintenance, or a combination of both (part 1.1). OR The entity's PSMP failed to include applicable station batteries in a time-based program (part 1.1). ~~.~~ ~~(Part 1.1).~~
R2	The ~~responsible~~ entity uses performance-based maintenance intervals in its PSMP but failed to reduce Countable Events to no more than 4% within three years.	NA	The ~~responsible~~ entity uses performance-based maintenance intervals in its PSMP but failed to reduce Countable Events to no more than 4% within four years.	The ~~responsible~~ entity uses performance-based maintenance intervals in its PSMP but: 1) Failed to establish the technical justification described within Requirement R2 for the initial use of the performance-based PSMP OR

Requirement Number	Lower VSL	Moderate VSL	High VSL	Severe VSL
				2) Failed to reduce Countable Events to no more than 4% within five years OR 3) Maintained a Segment with less than 60 Components OR 4) Failed to: • Annually update the list of Components, OR • Annually perform maintenance on the greater of 5% of the Segment population or 3 Components, OR • Annually analyze the program activities and results for each Segment.
R3	For Components included within a time-based maintenance program, the ~~responsible~~ entity failed to maintain 5% or less of the total Components included within a specific Component Type~~,~~ in accordance with the minimum maintenance activities and maximum maintenance intervals prescribed within Tables 1-1 through 1-5, Table 2, Table 3, ~~and~~ Tables 4-1 through 4-2, and Table 5.	For Components included within a time-based maintenance program, the ~~responsible~~ entity failed to maintain more than 5% but 10% or less of the total Components included within a specific Component Type~~,~~ in accordance with the minimum maintenance activities and maximum maintenance intervals prescribed within Tables 1-1 through 1-5, Table	For Components included within a time-based maintenance program, the ~~responsible~~ entity failed to maintain more than 10% but 15% or less of the total Components included within a specific Component Type~~,~~ in accordance with the minimum maintenance activities and maximum maintenance intervals prescribed within Tables 1-1 through 1-5, Table	For Components included within a time-based maintenance program, the ~~responsible~~ entity failed to maintain more than 15% of the total Components included within a specific Component Type~~,~~ in accordance with the minimum maintenance activities and maximum maintenance intervals prescribed within Tables 1-1 through 1-5, Table 2, Table 3, ~~and~~

Requirement Number	Lower VSL	Moderate VSL	High VSL	Severe VSL
	For Automatic Reclosing Components added to a time-based maintenance program per information from the Balancing Authority, the entity failed to maintain 5% or less of the total Components in accordance with the minimum maintenance activities and maximum maintenance intervals prescribed within Tables 4-1 through 4-2.	2, Table 3, ~~and~~ Tables 4-1 through 4-2, and Table 5. For Automatic Reclosing Components added to a time-based maintenance program per information from the Balancing Authority, the entity failed to maintain more than 5% but 10% or less of the total Components in accordance with the minimum maintenance activities and maximum maintenance intervals prescribed within Tables 4-1 through 4-2.	2, Table 3, ~~and~~ Tables 4-1 through 4-2, and Table 5. For Automatic Reclosing Components added to a time-based maintenance program per information from the Balancing Authority, the entity failed to maintain more than 10% but 15% or less of the total Components in accordance with the minimum maintenance activities and maximum maintenance intervals prescribed within Tables 4-1 through 4-2.	Tables 4-1 through 4-2, and Table 5. For Automatic Reclosing Components added to a time-based maintenance program per information from the Balancing Authority, the entity failed to maintain more than 15% of the total Components in accordance with the minimum maintenance activities and maximum maintenance intervals prescribed within Tables 4-1 through 4-2.
R4	For Components included within a performance-based maintenance program, the ~~responsible~~ entity failed to maintain 5% or less of the annual scheduled maintenance for a specific Component Type in accordance with their performance-based PSMP. For Automatic Reclosing Components added to a performance-based maintenance program per information from the Balancing Authority, the entity failed to maintain 5% or less of the total	For Components included within a performance-based maintenance program, the ~~responsible~~ entity failed to maintain more than 5% but 10% or less of the annual scheduled maintenance for a specific Component Type in accordance with their performance-based PSMP. For Automatic Reclosing Components added to a performance-based maintenance program per information from the Balancing Authority, the entity failed to maintain more than 5% but 10% or less of the total	For Components included within a performance-based maintenance program, the ~~responsible~~ entity failed to maintain more than 10% but 15% or less of the annual scheduled maintenance for a specific Component Type in accordance with their performance-based PSMP. For Automatic Reclosing Components added to a performance-based maintenance program per information from the Balancing Authority, the entity failed to maintain more than 10% but 15% or less of the total	For Components included within a performance-based maintenance program, the ~~responsible~~ entity failed to maintain more than 15% of the annual scheduled maintenance for a specific Component Type in accordance with their performance-based PSMP. For Automatic Reclosing Components added to a performance-based maintenance program per information from the Balancing Authority, the entity failed to maintain more than 15% of the total Components in

Requirement Number	Lower VSL	Moderate VSL	High VSL	Severe VSL
	Components in accordance with their performance-based PSMP.	Components in accordance with their performance-based PSMP.	Components in accordance with their performance-based PSMP.	accordance with their performance-based PSMP.
R5	The ~~responsible~~ entity failed to undertake efforts to correct 5 or fewer identified Unresolved Maintenance Issues.	The ~~responsible~~ entity failed to undertake efforts to correct greater than 5~~,~~ but less than or equal to 10 identified Unresolved Maintenance Issues.	The ~~responsible~~ entity failed to undertake efforts to correct greater than 10~~,~~ but less than or equal to 15 identified Unresolved Maintenance Issues.	The ~~responsible~~ entity failed to undertake efforts to correct greater than 15 identified Unresolved Maintenance Issues.
R6				The entity failed to notify each Transmission Owner, Generator Owner, and Distribution Provider within its Balancing Authority Area at least once every calendar year of the gross capacity, in MW or MVA, of the largest BES generating unit within the Balancing Authority Area. OR The entity had more than 15 calendar months between notifications to each Transmission Owner, Generator Owner, and Distribution Provider of the gross capacity, in MW or MVA, of the largest BES generating unit within the Balancing Authority Area.

D. Regional Variances

None.

E. Interpretations

None.

F. Supplemental Reference Documents

The following documents present a detailed discussion about determination of maintenance intervals and other useful information regarding establishment of a maintenance program.

1. *Supplementary Reference and FAQ - PRC-005-X~~2~~ Protection System Maintenance*, Protection System Maintenance and Testing Standard Drafting Team (April 2014) ~~Supplementary Reference and FAQ — March 2013.~~
2. *Considerations for Maintenance and Testing of Auto-reclosing~~Autoreclosing~~ Schemes*, NERC System Analysis and Modeling Subcommittee, and NERC System Protection and Control Subcommittee (~~—~~November 2012)~~.~~
3. *Sudden Pressure Relays and Other Devices that Respond to Non-Electrical Quantities – SPCS Input for Standard Development in Response to FERC Order No. 758,* NERC System Protection and Control Subcommittee (December 2013)

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
1	December 1, 2005	1. Changed incorrect use of certain hyphens (-) to “en dash” (–) and “em dash (—).” 2. Added “periods” to items where appropriate. 3. Changed “Timeframe” to “Time Frame” in item D, 1.2.	01/20/05
1a	February 17, 2011	Added Appendix 1 - Interpretation regarding applicability of standard to protection of radially connected transformers	Project 2009-17 interpretation

1a	February 17, 2011	Adopted by Board of Trustees	
1a	September 26, 2011	FERC Order issued approving interpretation of R1 and R2 (FERC's Order is effective as of September 26, 2011)	
1.1a	February 1, 2012	Errata change: Clarified inclusion of generator interconnection Facility in Generator Owner's responsibility	Revision under Project 2010-07
1b	February 3, 2012	FERC Order issued approving interpretation of R1, R1.1, and R1.2 (FERC's Order dated March 14, 2012). Updated version from 1a to 1b.	Project 2009-10 Interpretation
1.1b	April 23, 2012	Updated standard version to 1.1b to reflect FERC approval of PRC-005-1b.	Revision under Project 2010-07

1.1b	May 9, 2012	PRC-005-1.1b was adopted by the Board of Trustees as part of Project 2010-07 (Generator Requirements at the Transmission Interface~~GOTO~~).	
2	November 7, 2012	Adopted by Board of Trustees	Project 2007-17 - Complete revision, absorbing maintenance requirements from PRC-005-1.1b, PRC-008-0, PRC-011-0, PRC-017-0
2	October 17, 2013	Errata Change: The Standards Committee approved an errata change to the implementation plan for PRC-005-2 to add the phrase “or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities;” to the second sentence under the “Retirement of Existing	
3	November 7, 2013	Adopted by the NERC Board of Trustees	Revised to address the FERC directive in Order No.758 to include Automatic Reclosing in maintenance programs.
3.1	February 12, 2014	Approved by the Standards Committee	Errata changes to correct capitalization of defined terms
4			Project 2007-17.3 – Revised to address the FERC directive in Order No. 758 to include sudden pressure relays in maintenance programs.

Table 1-1 Component Type - Protective Relay Excluding distributed UFLS and distributed UVLS (see Table 3)		
Component Attributes	**Maximum Maintenance Interval[2]**	**Maintenance Activities**
Any unmonitored protective relay not having all the monitoring attributes of a category below.	6 Calendar Years	For all unmonitored relays: • Verify that settings are as specified For non-microprocessor relays: • Test and, if necessary calibrate For microprocessor relays: • Verify operation of the relay inputs and outputs that are essential to proper functioning of the Protection System. • Verify acceptable measurement of power system input values.
Monitored microprocessor protective relay with the following: • Internal self-diagnosis and alarming (see Table 2). • Voltage and/or current waveform sampling three or more times per power cycle, and conversion of samples to numeric values for measurement calculations by microprocessor electronics. • Alarming for power supply failure (see Table 2).	12 Calendar Years	Verify: • Settings are as specified. • Operation of the relay inputs and outputs that are essential to proper functioning of the Protection System. • Acceptable measurement of power system input values.

[2] For the tables in this standard, a calendar year starts on the first day of a new year (January 1) after a maintenance activity has been completed.
For the tables in this standard, a calendar month starts on the first day of the first month after a maintenance activity has been completed.

Table 1-1 Component Type - Protective Relay Excluding distributed UFLS and distributed UVLS (see Table 3)		
Component Attributes	**Maximum Maintenance Interval[2]**	**Maintenance Activities**
Monitored microprocessor protective relay with preceding row attributes and the following: • Ac measurements are continuously verified by comparison to an independent ac measurement source, with alarming for excessive error (See Table 2). • Some or all binary or status inputs and control outputs are monitored by a process that continuously demonstrates ability to perform as designed, with alarming for failure (See Table 2). • Alarming for change of settings (See Table 2).	12 Calendar Years	Verify only the unmonitored relay inputs and outputs that are essential to proper functioning of the Protection System.

Table 1-2 Component Type - Communications Systems Excluding distributed UFLS and distributed UVLS (see Table 3)		
Component Attributes	**Maximum Maintenance Interval**	**Maintenance Activities**
Any unmonitored communications system necessary for correct operation of protective functions, and not having all the monitoring attributes of a category below.	4 Calendar Months	Verify that the communications system is functional.
	6 Calendar Years	Verify that the communications system meets performance criteria pertinent to the communications technology applied (e.g. signal level, reflected power, or data error rate). Verify operation of communications system inputs and outputs that are essential to proper functioning of the Protection System.
Any communications system with continuous monitoring or periodic automated testing for the presence of the channel function, and alarming for loss of function (See Table 2).	12 Calendar Years	Verify that the communications system meets performance criteria pertinent to the communications technology applied (e.g. signal level, reflected power, or data error rate). Verify operation of communications system inputs and outputs that are essential to proper functioning of the Protection System.
Any communications system with all of the following: • Continuous monitoring or periodic automated testing for the performance of the channel using criteria pertinent to the communications technology applied (e.g. signal level, reflected power, or data error rate, and alarming for excessive performance degradation). (See Table 2) • Some or all binary or status inputs and control outputs are monitored by a process that continuously demonstrates ability to perform as designed, with alarming for failure (See Table 2).	12 Calendar Years	Verify only the unmonitored communications system inputs and outputs that are essential to proper functioning of the Protection System

Table 1-3 Component Type - Voltage and Current Sensing Devices Providing Inputs to Protective Relays Excluding distributed UFLS and distributed UVLS (see Table 3)		
Component Attributes	**Maximum Maintenance Interval**	**Maintenance Activities**
Any voltage and current sensing devices not having monitoring attributes of the category below.	12 Calendar Years	Verify that current and voltage signal values are provided to the protective relays.
Voltage and Current Sensing devices connected to microprocessor relays with AC measurements are continuously verified by comparison of sensing input value, as measured by the microprocessor relay, to an independent ac measurement source, with alarming for unacceptable error or failure (see Table 2).	No periodic maintenance specified	None.

Table 1-4(a) Component Type – Protection System Station dc Supply Using Vented Lead-Acid (VLA) Batteries Excluding distributed UFLS and distributed UVLS (see Table 3) Protection System Station dc supply used only for non-BES interrupting devices for SPS, non-distributed UFLS systems, or non-distributed UVLS systems is excluded (see Table 1-4(e)).		
Component Attributes	**Maximum Maintenance Interval**	**Maintenance Activities**
Protection System Station dc supply using **Vented Lead-Acid (VLA) batteries** not having monitoring attributes of Table 1-4(f).	4 Calendar Months	Verify: • Station dc supply voltage Inspect: • Electrolyte level • For unintentional grounds
	18 Calendar Months	Verify: • Float voltage of battery charger • Battery continuity • Battery terminal connection resistance • Battery intercell or unit-to-unit connection resistance Inspect: • Cell condition of all individual battery cells where cells are visible – or measure battery cell/unit internal ohmic values where the cells are not visible • Physical condition of battery rack

Table 1-4(a) Component Type – Protection System Station dc Supply Using Vented Lead-Acid (VLA) Batteries Excluding distributed UFLS and distributed UVLS (see Table 3) Protection System Station dc supply used only for non-BES interrupting devices for SPS, non-distributed UFLS systems, or non-distributed UVLS systems is excluded (see Table 1-4(e)).		
Component Attributes	**Maximum Maintenance Interval**	**Maintenance Activities**
	18 Calendar Months -or- 6 Calendar Years	Verify that the station battery can perform as manufactured by evaluating cell/unit measurements indicative of battery performance (e.g. internal ohmic values or float current) against the station battery baseline. -or- Verify that the station battery can perform as manufactured by conducting a performance or modified performance capacity test of the entire battery bank.

Table 1-4(b)

Component Type – Protection System Station dc Supply Using Valve-Regulated Lead-Acid (VRLA) Batteries

Excluding distributed UFLS and distributed UVLS (see Table 3)

Protection System Station dc supply used only for non-BES interrupting devices for SPS, non-distributed UFLS systems, or non-distributed UVLS systems is excluded (see Table 1-4(e)).

Component Attributes	Maximum Maintenance Interval	Maintenance Activities
Protection System Station dc supply **with Valve Regulated Lead-Acid (VRLA) batteries** not having monitoring attributes of Table 1-4(f).	4 Calendar Months	Verify: • Station dc supply voltage Inspect: • For unintentional grounds
	6 Calendar Months	Inspect: • Condition of all individual units by measuring battery cell/unit internal ohmic values.
	18 Calendar Months	Verify: • Float voltage of battery charger • Battery continuity • Battery terminal connection resistance • Battery intercell or unit-to-unit connection resistance Inspect: • Physical condition of battery rack

Table 1-4(b) Component Type – Protection System Station dc Supply Using Valve-Regulated Lead-Acid (VRLA) Batteries Excluding distributed UFLS and distributed UVLS (see Table 3) Protection System Station dc supply used only for non-BES interrupting devices for SPS, non-distributed UFLS systems, or non-distributed UVLS systems is excluded (see Table 1-4(e)).		
Component Attributes	**Maximum Maintenance Interval**	**Maintenance Activities**
	6 Calendar Months -or- 3 Calendar Years	Verify that the station battery can perform as manufactured by evaluating cell/unit measurements indicative of battery performance (e.g. internal ohmic values or float current) against the station battery baseline. -or- Verify that the station battery can perform as manufactured by conducting a performance or modified performance capacity test of the entire battery bank.

Table 1-4(c)

Component Type – Protection System Station dc Supply Using Nickel-Cadmium (NiCad) Batteries

Excluding distributed UFLS and distributed UVLS (see Table 3)

Protection System Station dc supply used only for non-BES interrupting devices for SPS, non-distributed UFLS system, or non-distributed UVLS systems is excluded (see Table 1-4(e)).

Component Attributes	Maximum Maintenance Interval	Maintenance Activities
Protection System Station dc supply **Nickel-Cadmium (NiCad) batteries** not having monitoring attributes of Table 1-4(f).	4 Calendar Months	Verify: • Station dc supply voltage Inspect: • Electrolyte level • For unintentional grounds
	18 Calendar Months	Verify: • Float voltage of battery charger • Battery continuity • Battery terminal connection resistance • Battery intercell or unit-to-unit connection resistance Inspect: • Cell condition of all individual battery cells. • Physical condition of battery rack

Table 1-4(c) Component Type – Protection System Station dc Supply Using Nickel-Cadmium (NiCad) Batteries Excluding distributed UFLS and distributed UVLS (see Table 3) Protection System Station dc supply used only for non-BES interrupting devices for SPS, non-distributed UFLS system, or non-distributed UVLS systems is excluded (see Table 1-4(e)).		
Component Attributes	Maximum Maintenance Interval	Maintenance Activities
	6 Calendar Years	Verify that the station battery can perform as manufactured by conducting a performance or modified performance capacity test of the entire battery bank.

Table 1-4(d) Component Type – Protection System Station dc Supply Using Non Battery Based Energy Storage Excluding distributed UFLS and distributed UVLS (see Table 3) Protection System Station dc supply used only for non-BES interrupting devices for SPS, non-distributed UFLS system, or non-distributed UVLS systems is excluded (see Table 1-4(e)).		
Component Attributes	**Maximum Maintenance Interval**	**Maintenance Activities**
Any Protection System station dc supply not using a battery and not having monitoring attributes of Table 1-4(f).	4 Calendar Months	Verify: • Station dc supply voltage Inspect: • For unintentional grounds
	18 Calendar Months	Inspect: Condition of non-battery based dc supply
	6 Calendar Years	Verify that the dc supply can perform as manufactured when ac power is not present.

Table 1-4(e) Component Type – Protection System Station dc Supply for non-BES Interrupting Devices for SPS, non-distributed UFLS, and non-distributed UVLS systems		
Component Attributes	**Maximum Maintenance Interval**	**Maintenance Activities**
Any Protection System dc supply used for tripping only non-BES interrupting devices as part of a SPS, non-distributed UFLS, or non-distributed UVLS system and not having monitoring attributes of Table 1-4(f).	When control circuits are verified (See Table 1-5)	Verify Station dc supply voltage.

Table 1-4(f) Exclusions for Protection System Station dc Supply Monitoring Devices and Systems		
Component Attributes	**Maximum Maintenance Interval**	**Maintenance Activities**
Any station dc supply with high and low voltage monitoring and alarming of the battery charger voltage to detect charger overvoltage and charger failure (See Table 2).	No periodic maintenance specified	No periodic verification of station dc supply voltage is required.
Any battery based station dc supply with electrolyte level monitoring and alarming in every cell (See Table 2).		No periodic inspection of the electrolyte level for each cell is required.
Any station dc supply with unintentional dc ground monitoring and alarming (See Table 2).		No periodic inspection of unintentional dc grounds is required.
Any station dc supply with charger float voltage monitoring and alarming to ensure correct float voltage is being applied on the station dc supply (See Table 2).		No periodic verification of float voltage of battery charger is required.
Any battery based station dc supply with monitoring and alarming of battery string continuity (See Table 2).		No periodic verification of the battery continuity is required.
Any battery based station dc supply with monitoring and alarming of the intercell and/or terminal connection detail resistance of the entire battery (See Table 2).		No periodic verification of the intercell and terminal connection resistance is required.
Any Valve Regulated Lead-Acid (VRLA) or Vented Lead-Acid (VLA) station battery with internal ohmic value or float current monitoring and alarming, and evaluating present values relative to baseline internal ohmic values for every cell/unit (See Table 2).		No periodic evaluation relative to baseline of battery cell/unit measurements indicative of battery performance is required to verify the station battery can perform as manufactured.
Any Valve Regulated Lead-Acid (VRLA) or Vented Lead-Acid (VLA) station battery with monitoring and alarming of each cell/unit internal ohmic value (See Table 2).		No periodic inspection of the condition of all individual units by measuring battery cell/unit internal ohmic values of a station VRLA or Vented Lead-Acid (VLA) battery is required.

Table 1-5 Component Type - Control Circuitry Associated With Protective Functions Excluding distributed UFLS and distributed UVLS (see Table 3) Note: Table requirements apply to all Control Circuitry Components of Protection Systems, and SPSs except as noted.		
Component Attributes	**Maximum Maintenance Interval**	**Maintenance Activities**
Trip coils or actuators of circuit breakers, interrupting devices, or mitigating devices (regardless of any monitoring of the control circuitry).	6 Calendar Years	Verify that each trip coil is able to operate the circuit breaker, interrupting device, or mitigating device.
Electromechanical lockout devices which are directly in a trip path from the protective relay to the interrupting device trip coil (regardless of any monitoring of the control circuitry).	6 Calendar Years	Verify electrical operation of electromechanical lockout devices.
Unmonitored control circuitry associated with SPS. (See Table 4-2(b) for SPS which include Automatic Reclosing.)	12 Calendar Years	Verify all paths of the control circuits essential for proper operation of the SPS.
Unmonitored control circuitry associated with protective functions inclusive of all auxiliary relays.	12 Calendar Years	Verify all paths of the trip circuits inclusive of all auxiliary relays through the trip coil(s) of the circuit breakers or other interrupting devices.
Control circuitry associated with protective functions and/or SPSs whose integrity is monitored and alarmed (See Table 2).	No periodic maintenance specified	None.

Table 2 – Alarming Paths and Monitoring In Tables 1-1 through 1-5, Table 3, and Tables 4-1 through 4-2, alarm attributes used to justify extended maximum maintenance intervals and/or reduced maintenance activities are subject to the following maintenance requirements		
Component Attributes	**Maximum Maintenance Interval**	**Maintenance Activities**
Any alarm path through which alarms in Tables 1-1 through 1-5, Table 3, and Tables 4-1 through 4-2 are conveyed from the alarm origin to the location where corrective action can be initiated, and not having all the attributes of the "Alarm Path with monitoring" category below. Alarms are reported within 24 hours of detection to a location where corrective action can be initiated.	12 Calendar Years	Verify that the alarm path conveys alarm signals to a location where corrective action can be initiated.
Alarm Path with monitoring: The location where corrective action is taken receives an alarm within 24 hours for failure of any portion of the alarming path from the alarm origin to the location where corrective action can be initiated.	No periodic maintenance specified	None.

Table 3 Maintenance Activities and Intervals for distributed UFLS and distributed UVLS Systems		
Component Attributes	**Maximum Maintenance Interval**	**Maintenance Activities**
Any unmonitored protective relay not having all the monitoring attributes of a category below.	6 Calendar Years	Verify that settings are as specified. For non-microprocessor relays: • Test and, if necessary calibrate. For microprocessor relays: • Verify operation of the relay inputs and outputs that are essential to proper functioning of the Protection System. • Verify acceptable measurement of power system input values.
Monitored microprocessor protective relay with the following: • Internal self-~~-~~diagnosis and alarming (See Table 2). • Voltage and/or current waveform sampling three or more times per power cycle, and conversion of samples to numeric values for measurement calculations by microprocessor electronics. Alarming for power supply failure (See Table 2).	12 Calendar Years	Verify: • Settings are as specified. • Operation of the relay inputs and outputs that are essential to proper functioning of the Protection System. • Acceptable measurement of power system input values
Monitored microprocessor protective relay with preceding row attributes and the following: • Ac measurements are continuously verified by comparison to an independent ac measurement source, with alarming for excessive error (See Table 2).	12 Calendar Years	Verify only the unmonitored relay inputs and outputs that are essential to proper functioning of the Protection System.

Table 3 Maintenance Activities and Intervals for distributed UFLS and distributed UVLS Systems		
Component Attributes	**Maximum Maintenance Interval**	**Maintenance Activities**
• Some or all binary or status inputs and control outputs are monitored by a process that continuously demonstrates ability to perform as designed, with alarming for failure (See Table 2). Alarming for change of settings (See Table 2).		
Voltage and/or current sensing devices associated with UFLS or UVLS systems.	12 Calendar Years	Verify that current and/or voltage signal values are provided to the protective relays.
Protection System dc supply for tripping non-BES interrupting devices used only for a UFLS or UVLS system.	12 Calendar Years	Verify Protection System dc supply voltage.
Control circuitry between the UFLS or UVLS relays and electromechanical lockout and/or tripping auxiliary devices (excludes non-BES interrupting device trip coils).	12 Calendar Years	Verify the path from the relay to the lockout and/or tripping auxiliary relay (including essential supervisory logic).
Electromechanical lockout and/or tripping auxiliary devices associated only with UFLS or UVLS systems (excludes non-BES interrupting device trip coils).	12 Calendar Years	Verify electrical operation of electromechanical lockout and/or tripping auxiliary devices.
Control circuitry between the electromechanical lockout and/or tripping auxiliary devices and the non-BES interrupting devices in UFLS or UVLS systems, or between UFLS or UVLS relays (with no interposing electromechanical lockout or auxiliary device) and the non-BES interrupting devices (excludes non-BES interrupting device trip coils).	No periodic maintenance specified	None.
Trip coils of non-BES interrupting devices in UFLS or UVLS systems.	No periodic maintenance specified	None.

Table 4-1 Maintenance Activities and Intervals for Automatic Reclosing Components Component Type – Reclosing Relay		
Component Attributes	**Maximum Maintenance Interval**	**Maintenance Activities**
Any unmonitored reclosing relay not having all the monitoring attributes of a category below.	6 Calendar Years	Verify that settings are as specified. For non-microprocessor relays: • Test and, if necessary calibrate For microprocessor relays: • Verify operation of the relay inputs and outputs that are essential to proper functioning of the Automatic Reclosing.
Monitored microprocessor reclosing relay with the following: • Internal self-diagnosis and alarming (See Table 2). • Alarming for power supply failure (See Table 2).	12 Calendar Years	Verify: • Settings are as specified. • Operation of the relay inputs and outputs that are essential to proper functioning of the Automatic Reclosing.

Table 4-2(a) Maintenance Activities and Intervals for Automatic Reclosing Components Component Type – Control Circuitry Associated with Reclosing Relays that are NOT an Integral Part of an SPS		
Component Attributes	**Maximum Maintenance Interval**	**Maintenance Activities**
Unmonitored Control circuitry associated with Automatic Reclosing that is not an integral part of an SPS.	12 Calendar Years	Verify that Automatic Reclosing, upon initiation, does not issue a premature closing command to the close circuitry.
Control circuitry associated with Automatic Reclosing that is not part of an SPS and is monitored and alarmed for conditions that would result in a premature closing command. (See Table 2)	No periodic maintenance specified	None.

Table 4-2(b) Maintenance Activities and Intervals for Automatic Reclosing Components Component Type – Control Circuitry Associated with Reclosing Relays that ARE an Integral Part of an SPS		
Component Attributes	**Maximum Maintenance Interval**	**Maintenance Activities**
Close coils or actuators of circuit breakers or similar devices that are used in conjunction with Automatic Reclosing as part of an SPS (regardless of any monitoring of the control circuitry).	6 Calendar Years	Verify that each close coil or actuator is able to operate the circuit breaker or mitigating device.
Unmonitored close control circuitry associated with Automatic Reclosing used as an integral part of an SPS.	12 Calendar Years	Verify all paths of the control circuits associated with Automatic Reclosing that are essential for proper operation of the SPS.
Control circuitry associated with Automatic Reclosing that is an integral part of an SPS whose integrity is monitored and alarmed. (See Table 2)	No periodic maintenance specified	None.

Table 5 Maintenance Activities and Intervals for Sudden Pressure Relaying		
Component Attributes	**Maximum Maintenance Interval**	**Maintenance Activities**
Any fault pressure relay.	6 Calendar Years	Verify the pressure or flow sensing mechanism is operable.
Control circuitry associated with Sudden Pressure Relaying from the fault pressure relay to the interrupting device trip coil(s).	12 Calendar Years	Verify all paths of the control circuits that are essential for proper operation of the Sudden Pressure Relaying.

PRC-005 — Attachment A

Criteria for a Performance-Based Protection System Maintenance Program

Purpose: To establish a technical basis for initial and continued use of a performance-based Protection System Maintenance Program (PSMP).

To establish the technical justification for the initial use of a performance-based PSMP:

1. Develop a list with a description of Components included in each designated Segment, with a minimum **Segment** population of 60 Components.
2. Maintain the Components in each Segment according to the time-based maximum allowable intervals established in Tables 1-1 through 1-5, Table 3, ~~and~~ Tables 4-1 through 4-2, and Table 5 until results of maintenance activities for the Segment are available for a minimum of 30 individual Components of the Segment.
3. Document the maintenance program activities and results for each Segment, including maintenance dates and Countable Events for each included Component.
4. Analyze the maintenance program activities and results for each Segment to determine the overall performance of the Segment and develop maintenance intervals.
5. Determine the maximum allowable maintenance interval for each Segment such that the Segment experiences **Countable Events** on no more than 4% of the Components within the Segment, for the greater of either the last 30 Components maintained or all Components maintained in the previous year.

To maintain the technical justification for the ongoing use of a performance-based PSMP:

1. At least annually, update the list of Components and Segments and/or description if any changes occur within the Segment.
2. Perform maintenance on the greater of 5% of the Components (addressed in the performance based PSMP) in each Segment or 3 individual Components within the Segment in each year.
3. For the prior year, analyze the maintenance program activities and results for each Segment to determine the overall performance of the Segment.
4. Using the prior year's data, determine the maximum allowable maintenance interval for each Segment such that the Segment experiences Countable Events on no more than 4% of the Components within the Segment, for the greater of either the last 30 Components maintained or all Components maintained in the previous year.

If the Components in a Segment maintained through a performance-based PSMP experience 4% or more Countable Events, develop, document, and implement an action plan to reduce the Countable Events to less than 4% of the Segment population within 3 years.

Implementation Plan

Protection System, Automatic Reclosing, and Sudden Pressure Relaying Maintenance
PRC-005-X

Standards Involved

Approval:

- PRC-005-X – Protection System, Automatic Reclosing, and Sudden Pressure Relaying Maintenance

Retirement:

- PRC-005-3 – Protection System and Automatic Reclosing Maintenance

Prerequisite Approvals:

N/A

Background:

Reliability Standard PRC-005-2 with its associated Implementation Plan was approved by FERC, effective on April 1, 2015. PRC-005-3 was approved by the NERC Board of Trustees in November 7, 2013 and has been filed with the applicable regulatory authorities for approval. The Implementation Plan for PRC-005-X addresses Protection Systems as outlined in PRC-005-2, Automatic Reclosing Components as outlined in PRC-005-3, and Sudden Pressure Relaying. PRC-005-X establishes minimum maintenance activities for Sudden Pressure Relaying Component Types and the maximum allowable maintenance intervals for these maintenance activities. PRC-005-X requires entities to revise the Protection System Maintenance Program by now including Sudden Pressure Relaying Components.

This Implementation Plan adds:

- The implementation of changes relating to Sudden Pressure Relaying maintenance and testing,
- The implementation of new Requirement R6 for Balancing Authorities, and
- The removal of the "Implementation Plan for Newly identified Automatic Reclosing Components Due to Generation Changes in the Balancing Authority Area" section, as the elements are now incorporated within the requirements of the standard itself.

Otherwise, the Implementation Plan has not been changed.

The Implementation Plan reflects consideration of the following:

1. The requirements set forth in the proposed standard, which carry forward requirements from PRC-005-2 and PRC-005-3, establish minimum maintenance activities for Protection System, Automatic Reclosing, and Sudden Pressure Relaying Component Types as well as the maximum allowable maintenance intervals for these maintenance activities. The maintenance activities established may not be presently performed by some entities and the established maximum allowable intervals may be shorter than those currently in use by some entities.
2. For entities not presently performing a maintenance activity or using longer intervals than the maximum allowable intervals established in the proposed standard, it is unrealistic for those entities to be immediately compliant with the new activities or intervals. Further, entities should be allowed to become compliant in such a way as to facilitate a continuing maintenance program.
3. Entities that have previously been performing maintenance within the newly specified intervals may not have all the documentation needed to demonstrate compliance with all of the maintenance activities specified.
4. The Implementation Schedule set forth below in this document carries forward the implementation schedules contained in PRC-005-2 and PRC-005-3 and includes changes needed to address the addition of Sudden Pressure Relaying Components in PRC-005-X.
5. The Implementation Schedule set forth in this document facilitates implementation of the more lengthy maintenance intervals within the revised Protection System Maintenance Program in approximately equally-distributed steps over those intervals prescribed for each respective maintenance activity in order that entities may implement this standard in a systematic method that facilitates an effective ongoing Protection System Maintenance Program.

General Considerations:

Each Transmission Owner, Generator Owner, and Distribution Provider shall maintain documentation to demonstrate compliance with PRC-005-1b, PRC-008-0, PRC-011-0, and PRC-017-0 until that entity meets the requirements of PRC-005-2, or the combined successor standards PRC-005-3 and PRC-005-X, in accordance with this implementation plan.

While entities are transitioning to the requirements of PRC-005-2, or the combined successor standards PRC-005-3 and PRC-005-X, each entity must be prepared to identify:

- All of its applicable Protection System, Automatic Reclosing, and Sudden Pressure Relaying Components, and
- Whether each component has last been maintained according to PRC-005-2 (or the combined successor standards PRC-005-3 and PRC-005-X), PRC-005-1b, PRC-008-0, PRC-011-0, PRC-017-0, or a combination thereof.

Effective Date

PRC-005-X shall become effective on the first day of the first calendar quarter after the date that the standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first calendar quarter after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

Retirement of Existing Standards:

Standards PRC-005-1b, PRC-008-0, PRC-011-0, and PRC-017-0 shall remain active throughout the phased implementation period of PRC-005-2 and shall be applicable to an entity's Protection System Component maintenance activities not yet transitioned to PRC-005-2. Standards PRC-005-1b, PRC-008-0, PRC-011-0, and PRC-017-0 shall be retired at midnight of the day immediately prior to the first day of the first calendar quarter one hundred fifty-six (156) months following applicable regulatory approval of PRC-005-2 or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities; or, in those jurisdictions where no regulatory approval is required, at midnight of the day immediately prior to the first day of the first calendar quarter one hundred sixty-eight (168) months following the November 2012 NERC Board of Trustees' adoption of PRC-005-2.

PRC-005-2 shall be retired at midnight of the day immediately prior to the first day of the first calendar quarter, twelve (12) calendar months following applicable regulatory approval of PRC-005-3, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities; or, in those jurisdictions where no regulatory approval is required, the first day of the first calendar quarter twelve (12) calendar months from the date of Board of Trustees' adoption.

PRC-005-3 shall be retired at midnight of the day immediately prior to the first day of the first calendar quarter following applicable regulatory approval of PRC-005-X, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities; or, in those jurisdictions where no regulatory approval is required, the first day of the first calendar quarter from the date of Board of Trustees' adoption.

Implementation Plan for Definitions:

This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the Reliability Standards Glossary of Terms (Glossary) are not repeated here. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, the Glossary definition will be removed from the individual standard and added to the Glossary. The definitions of terms used only in the standard will remain in the standard.

Glossary Definition:

Protection System Maintenance Program (PSMP) — An ongoing program by which Protection System, Automatic Reclosing, and Sudden Pressure Relaying Components are kept in working order and proper operation of malfunctioning Components is restored. A maintenance program for a specific Component includes one or more of the following activities:

- Verify — Determine that the Component is functioning correctly.
- Monitor — Observe the routine in-service operation of the Component.
- Test — Apply signals to a Component to observe functional performance or output behavior, or to diagnose problems.
- Inspect — Examine for signs of Component failure, reduced performance or degradation.
- Calibrate — Adjust the operating threshold or measurement accuracy of a measuring element to meet the intended performance requirement.

Definitions of Terms Used in the Standard:

Sudden Pressure Relaying – A system that trips an interrupting device(s) to isolate the equipment it is monitoring and includes the following Components:

- Fault pressure relay – a mechanical relay or device that detects rapid changes in gas pressure, oil pressure, or oil flow that are indicative of Faults within liquid-filled, wire-wound equipment
- Control circuitry associated with a fault pressure relay

Component Type –

- Any one of the five specific elements of a Protection System.
- Any one of the two specific elements of Automatic Reclosing.
- Any one of the two specific elements of Sudden Pressure Relaying.

Component – Any individual discrete piece of equipment included in a Protection System, Automatic Reclosing, or Sudden Pressure Relaying.

Countable Event – A failure of a Component requiring repair or replacement, any condition discovered during the maintenance activities in Tables 1-1 through 1-5, Table 3, Tables 4-1 through 4-2, and Table 5, which requires corrective action or a Protection System Misoperation attributed to hardware failure or calibration failure. Misoperations due to product design errors, software errors, relay settings different from specified settings, Protection System Component, Automatic Reclosing, or Sudden Pressure Relaying configuration or application errors are not included in Countable Events.

Implementation Plan for New or Revised Definitions:

New and revised definitions (Sudden Pressure Relaying, Protection System Maintenance Program, Component Type, Component, and Countable Event) shall become effective after the date that the definitions are approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a definition to go into effect. Where approval by an applicable governmental authority is not required, the definitions shall become effective on the first day of the first calendar quarter after the date the definitions are adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

Implementation Plan for Requirements R1, R2, and R5:

For Protection System Components, entities shall be 100% compliant on the first day of the first calendar quarter twelve (12) months following applicable regulatory approvals of PRC-005-2 or, in those jurisdictions where no regulatory approval is required, on the first day of the first calendar quarter twenty-four (24) months following the November 2012 NERC Board of Trustees' adoption of PRC-005-2 or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

For Automatic Reclosing Components, entities shall be 100% compliant on the first day of the first calendar quarter twelve (12) months following applicable regulatory approvals of PRC-005-3 or, in those jurisdictions where no regulatory approval is required, on the first day of the first calendar quarter twenty-four (24) months following NERC Board of Trustees' adoption of PRC-005-3 or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

For Sudden Pressure Relaying Components, entities shall be 100% compliant on the first day of the first calendar quarter twelve (12) months following applicable regulatory approvals of PRC-005-X or, in those jurisdictions where no regulatory approval is required, on the first day of the first calendar quarter twenty-four (24) months following NERC Board of Trustees' adoption of PRC-005-X or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

Implementation Plan for Requirements R3 and R4:

1. For Protection System Component maintenance activities with maximum allowable intervals of less than one (1) calendar year, as established in Tables 1-1 through 1-5:
    - The entity shall be 100% compliant on the first day of the first calendar quarter eighteen (18) months following applicable regulatory approval of PRC-005-2, or in those jurisdictions where no regulatory approval is required, on the first day of the first calendar quarter thirty (30) months following the November 2012 NERC Board of Trustees' adoption of PRC-005-2 or as

otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

2. For Protection System Component maintenance activities with maximum allowable intervals one (1) calendar year or more, but two (2) calendar years or less, as established in Tables 1-1 through 1-5:

   - The entity shall be 100% compliant on the first day of the first calendar quarter thirty-six (36) months following applicable regulatory approval of PRC-005-2 or, in those jurisdictions where no regulatory approval is required, on the first day of the first calendar quarter forty-eight (48) months following the November 2012 NERC Board of Trustees' adoption of PRC-005-2 or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

3. For Protection System Component maintenance activities with maximum allowable intervals of three (3) calendar years, as established in Tables 1-1 through 1-5:

   - The entity shall be at least 30% compliant on the first day of the first calendar quarter twenty-four (24) months following applicable regulatory approval of PRC-005-2 (or, for generating plants with scheduled outage intervals exceeding two years, at the conclusion of the first succeeding maintenance outage) or, in those jurisdictions where no regulatory approval is required, on the first day of the first calendar quarter thirty-six (36) months following the November 2012 NERC Board of Trustees' adoption of PRC-005-2 or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.
   - The entity shall be at least 60% compliant on the first day of the first calendar quarter thirty-six (36) months following applicable regulatory approval of PRC-005-2 or, in those jurisdictions where no regulatory approval is required, on the first day of the first calendar quarter forty-eight (48) months following NERC Board of Trustees' adoption of PRC-005-2 or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.
   - The entity shall be 100% compliant on the first day of the first calendar quarter forty-eight (48) months following applicable regulatory approval of PRC-005-2 or, in those jurisdictions where no regulatory approval is required, on the first day of the first calendar quarter sixty (60) months following the November 2012 NERC Board of Trustees' adoption of PRC-005-2 or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

4. For Protection System Component maintenance activities with maximum allowable intervals of six (6) calendar years, as established in Tables 1-1 through 1-5 and Table 3:

   - The entity shall be at least 30% compliant on the first day of the first calendar quarter thirty-six (36) months following applicable regulatory approval of PRC-005-2 (or, for generating plants with scheduled outage intervals exceeding three years, at the conclusion of the first succeeding maintenance outage) or, in those jurisdictions where no regulatory approval is required, on the

first day of the first calendar quarter forty-eight (48) months following the November 2012 NERC Board of Trustees' adoption of PRC-005-2 or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

- The entity shall be at least 60% compliant on the first day of the first calendar quarter sixty (60) months following applicable regulatory approval of PRC-005-2 or, in those jurisdictions where no regulatory approval is required, on the first day of the first calendar quarter seventy-two (72) months following the November 2012 NERC Board of Trustees' adoption of PRC-005-2 or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.
- The entity shall be 100% compliant on the first day of the first calendar quarter eighty-four (84) months following applicable regulatory approval of PRC-005-2 or, in those jurisdictions where no regulatory approval is required, on the first day of the first calendar quarter ninety-six (96) months following the November 2012 NERC Board of Trustees' adoption of PRC-005-2 or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

5. For Automatic Reclosing Component maintenance activities with maximum allowable intervals of six (6) calendar years, as established in Table 4-1, 4-2(a) and 4-2(b):

- The entity shall be at least 30% compliant on the first day of the first calendar quarter thirty-six (36) months following applicable regulatory approval of PRC-005-3 (or, for generating plants with scheduled outage intervals exceeding three years, at the conclusion of the first succeeding maintenance outage) or, in those jurisdictions where no regulatory approval is required, on the first day of the first calendar quarter forty-eight (48) months following NERC Board of Trustees' adoption of PRC-005-3 or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.
- The entity shall be at least 60% compliant on the first day of the first calendar quarter sixty (60) months following applicable regulatory approval of PRC-005-3 or, in those jurisdictions where no regulatory approval is required, on the first day of the first calendar quarter seventy-two (72) months following NERC Board of Trustees' adoption of PRC-005-3, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.
- The entity shall be 100% compliant on the first day of the first calendar quarter eighty-four (84) months following applicable regulatory approval of PRC-005-3 or, in those jurisdictions where no regulatory approval is required, on the first day of the first calendar quarter ninety-six (96) months following NERC Board of Trustees' adoption of PRC-005-3 or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

6. For Sudden Pressure Relaying Component maintenance activities with maximum allowable intervals of six (6) calendar years, as established in Table 5:

- The entity shall be at least 30% compliant on the first day of the first calendar quarter thirty-six (36) months following applicable regulatory approval of PRC-005-X (or, for generating plants with scheduled outage intervals exceeding three years, at the conclusion of the first succeeding maintenance outage) or, in those jurisdictions where no regulatory approval is required, on the first day of the first calendar quarter forty-eight (48) months following NERC Board of Trustees' adoption of PRC-005-X or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.
- The entity shall be at least 60% compliant on the first day of the first calendar quarter sixty (60) months following applicable regulatory approval of PRC-005-X or, in those jurisdictions where no regulatory approval is required, on the first day of the first calendar quarter seventy-two (72) months following NERC Board of Trustees' adoption of PRC-005-X, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.
- The entity shall be 100% compliant on the first day of the first calendar quarter eighty-four (84) months following applicable regulatory approval of PRC-005-X or, in those jurisdictions where no regulatory approval is required, on the first day of the first calendar quarter ninety-six (96) months following NERC Board of Trustees' adoption of PRC-005-X or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

7. For Protection System Component maintenance activities with maximum allowable intervals of twelve (12) calendar years, as established in Tables 1-1 through 1-5, Table 2, and Table 3:

   - The entity shall be at least 30% compliant on the first day of the first calendar quarter sixty (60) months following applicable regulatory approval of PRC-005-2 or, in those jurisdictions where no regulatory approval is required, on the first day of the first calendar quarter seventy-two (72) months following the November 2012 NERC Board of Trustees' adoption of PRC-005-2 or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.
   - The entity shall be at least 60% compliant on the first day of the first calendar quarter following one hundred eight (108) months following applicable regulatory approval of PRC-005-2 or, in those jurisdictions where no regulatory approval is required, on the first day of the first calendar quarter one hundred twenty (120) months following the November 2012 NERC Board of Trustees' adoption of PRC-005-2 or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.
   - The entity shall be 100% compliant on the first day of the first calendar quarter one hundred fifty-six (156) months following applicable regulatory approval of PRC-005-2 or, in those jurisdictions where no regulatory approval is required, on the first day of the first calendar quarter one hundred sixty-eight (168) months following the November 2012 NERC Board of Trustees' adoption of PRC-005-2 or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

8. For Automatic Reclosing Component maintenance activities with maximum allowable intervals of twelve (12) calendar years, as established in Table 4:
   - The entity shall be at least 30% compliant on the first day of the first calendar quarter sixty (60) months following applicable regulatory approval of PRC-005-3 or, in those jurisdictions where no regulatory approval is required, on the first day of the first calendar quarter seventy-two (72) months following NERC Board of Trustees’ adoption of PRC-005-3 or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.
   - The entity shall be at least 60% compliant on the first day of the first calendar quarter following one hundred eight (108) months following applicable regulatory approval of PRC-005-3 or, in those jurisdictions where no regulatory approval is required, on the first day of the first calendar quarter one hundred twenty (120) months following NERC Board of Trustees’ adoption of PRC-005-3 or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.
   - The entity shall be 100% compliant on the first day of the first calendar quarter one hundred fifty-six (156) months following applicable regulatory approval of PRC-005-3 or, in those jurisdictions where no regulatory approval is required, on the first day of the first calendar quarter one hundred sixty-eight (168) months following NERC Board of Trustees’ adoption of PRC-005-3 or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.
9. For Sudden Pressure Relaying Component maintenance activities with maximum allowable intervals of twelve (12) calendar years, as established in Table 5:
   - The entity shall be at least 30% compliant on the first day of the first calendar quarter sixty (60) months following applicable regulatory approval of PRC-005-X or, in those jurisdictions where no regulatory approval is required, on the first day of the first calendar quarter seventy-two (72) months following NERC Board of Trustees’ adoption of PRC-005-X or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.
   - The entity shall be at least 60% compliant on the first day of the first calendar quarter following one hundred eight (108) months following applicable regulatory approval of PRC-005-X or, in those jurisdictions where no regulatory approval is required, on the first day of the first calendar quarter one hundred twenty (120) months following NERC Board of Trustees’ adoption of PRC-005-X or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.
   - The entity shall be 100% compliant on the first day of the first calendar quarter one hundred fifty-six (156) months following applicable regulatory approval of PRC-005-X or, in those jurisdictions where no regulatory approval is required, on the first day of the first calendar quarter one hundred sixty-eight (168) months following NERC Board of Trustees’ adoption of PRC-005-X or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

Applicability:

This standard applies to the following functional entities:

- Transmission Owner
- Generator Owner
- Distribution Provider
- Balancing Authority

Implementation Plan

Protection System ~~and~~, Automatic Reclosing, and Sudden Pressure Relaying Maintenance
PRC-005-~~3~~X

Standards Involved

Approval:

- PRC-005-X – Protection System, Automatic Reclosing, and Sudden Pressure Relaying Maintenance

Retirement:

- PRC-005-3 – Protection System and Automatic Reclosing Maintenance

~~Retirements:~~

- ~~PRC-005-2 – Protection System Maintenance~~
- ~~PRC-005-1b – Transmission and Generation Protection System Maintenance and Testing~~
- ~~PRC-008-0 – Implementation and Documentation of Underfrequency Load Shedding Equipment Maintenance Program~~
- ~~PRC-011-0 – Undervoltage Load Shedding System Maintenance and Testing~~
- ~~PRC-017-0 – Special Protection System Maintenance and Testing~~

Prerequisite Approvals:

N/A

Background:

Reliability Standard PRC-005-2 with its associated Implementation Plan was approved by FERC, effective on April 1, 2015. PRC-005-3 was approved by the NERC Board of Trustees in November ~~2012~~7, 2013 and has been filed with the applicable regulatory authorities for approval. The Implementation Plan for PRC-005-~~3~~X addresses ~~both~~ Protection Systems as outlined in PRC-005-2~~ and~~, Automatic Reclosing ~~components.~~ Components as outlined in PRC-005-3, and Sudden Pressure Relaying. PRC-005-X establishes minimum maintenance activities for ~~Automatic Reclosing~~Sudden Pressure Relaying Component Types and the maximum allowable maintenance intervals for these maintenance activities. PRC-005-~~3~~X requires entities to revise the Protection System Maintenance Program by now including ~~Automatic Reclosing~~Sudden Pressure Relaying Components.

This Implementation Plan adds:

- The implementation ~~plan established under PRC-005-2 remains unchanged except~~of changes relating to Sudden Pressure Relaying maintenance and testing,
- The implementation of new Requirement R6 for Balancing Authorities, and
- The removal of the ~~addition of~~"Implementation Plan for Newly identified Automatic Reclosing Components ~~required under PRC-005-3.~~Due to Generation Changes in the Balancing Authority Area" section, as the elements are now incorporated within the requirements of the standard itself.

Otherwise, the Implementation Plan has not been changed.

The Implementation Plan reflects consideration of the following:

1. The requirements set forth in the proposed standard, which carry~~-~~ forward requirements from PRC-005-2 and PRC-005-3, establish minimum maintenance activities for Protection System~~ and~~, Automatic Reclosing, and Sudden Pressure Relaying Component Types as well as the maximum allowable maintenance intervals for these maintenance activities. The maintenance activities established may not be presently performed by some entities and the established maximum allowable intervals may be shorter than those currently in use by some entities.
2. For entities not presently performing a maintenance activity or using longer intervals than the maximum allowable intervals established in the proposed standard, it is unrealistic for those entities to be immediately compliant with the new activities or intervals. Further, entities should be allowed to become compliant in such a way as to facilitate a continuing maintenance program.
3. Entities that have previously been performing maintenance within the newly specified intervals may not have all the documentation needed to demonstrate compliance with all of the maintenance activities specified.
4. The Implementation Schedule set forth below in this document carries forward the implementation schedules contained in PRC-005-2 and PRC-005-3 and includes changes needed to address the addition of ~~Automatic Reclosing~~Sudden Pressure Relaying Components in PRC-005-~~3~~X.
5. The Implementation Schedule set forth in this document facilitates implementation of the more lengthy maintenance intervals within the revised Protection System Maintenance Program in approximately equally-distributed steps over those intervals prescribed for each respective maintenance activity in order that entities may implement this standard in a systematic method that facilitates an effective ongoing Protection System Maintenance Program.

General Considerations:

Each Transmission Owner, Generator Owner, and Distribution Provider shall maintain documentation to demonstrate compliance with PRC-005-1b, PRC-008-0, PRC-011-0, and PRC-017-0 until that entity meets the requirements of PRC-005-2, or the combined successor ~~standard~~standards PRC-005-3 and PRC-005-X, in accordance with this implementation plan.

While entities are transitioning to the requirements of PRC-005-2, or the combined successor ~~standard~~standards PRC-005-3 and PRC-005-X, each entity must be prepared to identify:

- All of its applicable Protection System ~~and~~, Automatic Reclosing, and Sudden Pressure Relaying Components~~.~~, and
- Whether each component has last been maintained according to PRC-005-2 (or the combined successor ~~standard~~standards PRC-005-3 and PRC-005-X), PRC-005-1b, PRC-008-0, PRC-011-0, PRC-017-0, or a combination thereof.

~~For activities being added to an entity's program as part of PRC-005-3 implementation, evidence may be available to show only a single performance of the activity until two maintenance intervals have transpired following initial implementation of PRC-005-3.~~

Effective Date

PRC-005-X shall become effective on the first day of the first calendar quarter after the date that the standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first calendar quarter after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

Retirement of Existing Standards:

Standards PRC-005-1b, PRC-008-0, PRC-011-0, and PRC-017-0 shall remain active throughout the phased implementation period of PRC-005-~~3~~2 and shall be applicable to an entity's Protection System Component maintenance activities not yet transitioned to PRC-005-~~3~~2. Standards PRC-005-1b, PRC-008-0, PRC-011-0, and PRC-017-0 shall be retired at midnight of the day immediately prior to the first day of the first calendar quarter one hundred fifty-six (156) months following applicable regulatory approval of PRC-005-2 or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities; or, in those jurisdictions where no regulatory approval is required, at midnight of the day immediately prior to the first day of the first calendar quarter one hundred sixty-eight (168) months following the November 2012 NERC Board of Trustees' adoption of PRC-005-2.

~~The existing standard~~ PRC-005-2 shall be retired at midnight of the day immediately prior to the first day of the first calendar quarter, twelve (12) calendar months following applicable regulatory approval of PRC-005-3, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities; or, in those jurisdictions where no regulatory approval is required, the first day of the first calendar quarter twelve (12) calendar months from the date of Board of Trustees' adoption.

PRC-005-3 shall be retired at midnight of the day immediately prior to the first day of the first calendar quarter following applicable regulatory approval of PRC-005-X, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities; or, in those jurisdictions where no regulatory approval is required, the first day of the first calendar quarter from the date of Board of Trustees' adoption.

Implementation Plan for Definitions:

This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the Reliability Standards Glossary of Terms (Glossary) are not repeated here. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, the Glossary definition will be removed from the individual standard and added to the Glossary. The definitions of terms used only in the standard will remain in the standard.

Glossary Definition:

Protection System Maintenance Program ~~– Entities~~**(PSMP) —** An ongoing program by which Protection System, Automatic Reclosing, and Sudden Pressure Relaying Components are kept in working order and proper operation of malfunctioning Components is restored. A maintenance program for a specific Component includes one or more of the following activities:

- Verify — Determine that the Component is functioning correctly.
- Monitor — Observe the routine in-service operation of the Component.
- Test — Apply signals to a Component to observe functional performance or output behavior, or to diagnose problems.
- Inspect — Examine for signs of Component failure, reduced performance or degradation.
- Calibrate — Adjust the operating threshold or measurement accuracy of a measuring element to meet the intended performance requirement.

Definitions of Terms Used in the Standard:

Sudden Pressure Relaying – A system that trips an interrupting device(s) to isolate the equipment it is monitoring and includes the following Components:

- Fault pressure relay – a mechanical relay or device that detects rapid changes in gas pressure, oil pressure, or oil flow that are indicative of Faults within liquid-filled, wire-wound equipment
- Control circuitry associated with a fault pressure relay

Component Type –

- Any one of the five specific elements of a Protection System.
- Any one of the two specific elements of Automatic Reclosing.
- Any one of the two specific elements of Sudden Pressure Relaying.

Component – Any individual discrete piece of equipment included in a Protection System, Automatic Reclosing, or Sudden Pressure Relaying.

Countable Event – A failure of a Component requiring repair or replacement, any condition discovered during the maintenance activities in Tables 1-1 through 1-5, Table 3, Tables 4-1 through 4-2, and Table 5, which requires corrective action or a Protection System Misoperation attributed to hardware failure or calibration failure. Misoperations due to product design errors, software errors, relay settings different from specified settings, Protection System

Component, Automatic Reclosing, or Sudden Pressure Relaying configuration or application errors are not included in Countable Events.

Implementation Plan for New or Revised Definitions:

New and revised definitions (Sudden Pressure Relaying, Protection System Maintenance Program, Component Type, Component, and Countable Event) shall ~~use this~~become effective after the date that the definitions are approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a definition ~~when implementing any portions of R1, R2 R3, R4 and R5 which use this defined term~~to go into effect. Where approval by an applicable governmental authority is not required, the definitions shall become effective on the first day of the first calendar quarter after the date the definitions are adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

Implementation Plan for Requirements R1, R2, and R5:

For Protection System Components, entities shall be 100% compliant on the first day of the first calendar quarter twelve (12) months following applicable regulatory approvals of PRC-005-2~~,~~ or, in those jurisdictions where no regulatory approval is required, on the first day of the first calendar quarter twenty-four (24) months following the November 2012 NERC Board of Trustees' adoption of PRC-005-2 or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

For Automatic Reclosing Components, entities shall be 100% compliant on the first day of the first calendar quarter twelve (12) months following applicable regulatory approvals of PRC-005-3~~,~~ or, in those jurisdictions where no regulatory approval is required, on the first day of the first calendar quarter twenty-four (24) months following NERC Board of Trustees' adoption of PRC-005-3 or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

For Sudden Pressure Relaying Components, entities shall be 100% compliant on the first day of the first calendar quarter twelve (12) months following applicable regulatory approvals of PRC-005-X or, in those jurisdictions where no regulatory approval is required, on the first day of the first calendar quarter twenty-four (24) months following NERC Board of Trustees' adoption of PRC-005-X or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

Implementation Plan for Requirements R3 and R4:

1. For Protection System Component maintenance activities with maximum allowable intervals of less than one (1) calendar year, as established in Tables 1-1 through 1-5:
   - The entity shall be 100% compliant on the first day of the first calendar quarter eighteen (18) months following applicable regulatory approval of PRC-005-2, or in those jurisdictions where no regulatory approval is required, on the first day of the first calendar quarter thirty (30) months following the November 2012 NERC Board of Trustees' adoption of PRC-005-2 or as

otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

2. For Protection System Component maintenance activities with maximum allowable intervals one (1) calendar year or more, but two (2) calendar years or less, as established in Tables 1-1 through 1-5:

   - The entity shall be 100% compliant on the first day of the first calendar quarter thirty-six (36) months following applicable regulatory approval of PRC-005-2~~,~~ or, in those jurisdictions where no regulatory approval is required, on the first day of the first calendar quarter forty-eight (48) months following the November 2012 NERC Board of Trustees' adoption of PRC-005-2 or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

3. For Protection System Component maintenance activities with maximum allowable intervals of three (3) calendar years, as established in Tables 1-1 through 1-5:

   - The entity shall be at least 30% compliant on the first day of the first calendar quarter twenty-four (24) months following applicable regulatory approval of PRC-005-2 (or, for generating plants with scheduled outage intervals exceeding two years, at the conclusion of the first succeeding maintenance outage~~),~~) or, in those jurisdictions where no regulatory approval is required, on the first day of the first calendar quarter thirty-six (36) months following the November 2012 NERC Board of Trustees' adoption of PRC-005-2 or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.
   - The entity shall be at least 60% compliant on the first day of the first calendar quarter thirty-six (36) months following applicable regulatory approval of PRC-005-2 or, in those jurisdictions where no regulatory approval is required, on the first day of the first calendar quarter forty-eight (48) months following NERC Board of Trustees' adoption of PRC-005-2 or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.
   - The entity shall be 100% compliant on the first day of the first calendar quarter forty-eight (48) months following applicable regulatory approval of PRC-005-2~~,~~ or, in those jurisdictions where no regulatory approval is required, on the first day of the first calendar quarter sixty (60) months following the November 2012 NERC Board of Trustees' adoption of PRC-005-2 or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

4. For Protection System Component maintenance activities with maximum allowable intervals of six (6) calendar years, as established in Tables 1-1 through 1-5 and Table 3:

   - The entity shall be at least 30% compliant on the first day of the first calendar quarter thirty-six (36) months following applicable regulatory approval of PRC-005-2 (or, for generating plants with scheduled outage intervals exceeding three years, at the conclusion of the first succeeding maintenance outage~~),~~) or, in those jurisdictions where no regulatory approval is required, on the first day of the first calendar quarter forty-eight (48) months following the November 2012 NERC Board of Trustees' adoption of PRC-005-2 or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

- The entity shall be at least 60% compliant on the first day of the first calendar quarter sixty (60) months following applicable regulatory approval of PRC-005-2~~,~~ or, in those jurisdictions where no regulatory approval is required, on the first day of the first calendar quarter seventy-two (72) months following the November 2012 NERC Board of Trustees' adoption of PRC-005-2 or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.
- The entity shall be 100% compliant on the first day of the first calendar quarter eighty-four (84) months following applicable regulatory approval of PRC-005-2~~,~~ or, in those jurisdictions where no regulatory approval is required, on the first day of the first calendar quarter ninety-six (96) months following the November 2012 NERC Board of Trustees' adoption of PRC-005-2 or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

5. For Automatic Reclosing Component maintenance activities with maximum allowable intervals of six (6) calendar years, as established in Table 4~~:~~-1, 4-2(a) and 4-2(b):

- The entity shall be at least 30% compliant on the first day of the first calendar quarter thirty-six (36) months following applicable regulatory approval of PRC-005-3 (or, for generating plants with scheduled outage intervals exceeding three years, at the conclusion of the first succeeding maintenance outage~~),~~) or, in those jurisdictions where no regulatory approval is required, on the first day of the first calendar quarter forty-eight (48) months following NERC Board of Trustees' adoption of PRC-005-3 or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.
- The entity shall be at least 60% compliant on the first day of the first calendar quarter sixty (60) months following applicable regulatory approval of PRC-005-3~~,~~ or, in those jurisdictions where no regulatory approval is required, on the first day of the first calendar quarter seventy-two (72) months following NERC Board of Trustees' adoption of PRC-005-3, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.
- The entity shall be 100% compliant on the first day of the first calendar quarter eighty-four (84) months following applicable regulatory approval of PRC-005-3~~,~~ or, in those jurisdictions where no regulatory approval is required, on the first day of the first calendar quarter ninety-six (96) months following NERC Board of Trustees' adoption of PRC-005-3 or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

6. For Sudden Pressure Relaying Component maintenance activities with maximum allowable intervals of six (6) calendar years, as established in Table 5:

- The entity shall be at least 30% compliant on the first day of the first calendar quarter thirty-six (36) months following applicable regulatory approval of PRC-005-X (or, for generating plants with scheduled outage intervals exceeding three years, at the conclusion of the first succeeding maintenance outage) or, in those jurisdictions where no regulatory approval is required, on the first day of the first calendar quarter forty-eight (48) months following NERC Board of Trustees' adoption of PRC-005-X or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.
- The entity shall be at least 60% compliant on the first day of the first calendar quarter sixty (60) months following applicable regulatory approval of PRC-005-X or, in those jurisdictions where no regulatory approval is required, on the first day of the first calendar quarter seventy-two (72) months following NERC Board of Trustees' adoption of PRC-005-X, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.
- The entity shall be 100% compliant on the first day of the first calendar quarter eighty-four (84) months following applicable regulatory approval of PRC-005-X or, in those jurisdictions where no regulatory approval is required, on the first day of the first calendar quarter ninety-six (96) months following NERC Board of Trustees' adoption of PRC-005-X or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

~~6.~~7. For Protection System Component maintenance activities with maximum allowable intervals of twelve (12) calendar years, as established in Tables 1-1 through 1-5, Table 2, and Table 3:

- The entity shall be at least 30% compliant on the first day of the first calendar quarter sixty (60) months following applicable regulatory approval of PRC-005-2 or, in those jurisdictions where no regulatory approval is required, on the first day of the first calendar quarter seventy-two (72) months following the November 2012 NERC Board of Trustees' adoption of PRC-005-2 or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.
- The entity shall be at least 60% compliant on the first day of the first calendar quarter following one hundred eight (108) months following applicable regulatory approval of PRC-005-2 or, in those jurisdictions where no regulatory approval is required, on the first day of the first calendar quarter one hundred twenty (120) months following the November 2012 NERC Board of Trustees' adoption of PRC-005-2 or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.
- The entity shall be 100% compliant on the first day of the first calendar quarter one hundred fifty-six (156) months following applicable regulatory approval of PRC-005-2 or, in those jurisdictions where no regulatory approval is required, on the first day of the first calendar quarter one hundred sixty-eight (168) months following the November 2012 NERC Board of Trustees' adoption of PRC-005-2 or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

~~7.~~8. For Automatic Reclosing Component maintenance activities with maximum allowable intervals of twelve (12) calendar years, as established in Table 4:

- The entity shall be at least 30% compliant on the first day of the first calendar quarter sixty (60) months following applicable regulatory approval of PRC-005-3 or, in those jurisdictions where no regulatory approval is required, on the first day of the first calendar quarter seventy-two (72) months following NERC Board of Trustees' adoption of PRC-005-3 or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.
- The entity shall be at least 60% compliant on the first day of the first calendar quarter following one hundred eight (108) months following applicable regulatory approval of PRC-005-3 or, in those jurisdictions where no regulatory approval is required, on the first day of the first calendar quarter one hundred twenty (120) months following NERC Board of Trustees' adoption of PRC-005-3 or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.
- The entity shall be 100% compliant on the first day of the first calendar quarter one hundred fifty-six (156) months following applicable regulatory approval of PRC-005-3 or, in those jurisdictions where no regulatory approval is required, on the first day of the first calendar quarter one hundred sixty-eight (168) months following NERC Board of Trustees' adoption of PRC-005-3 or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

~~Implementation Plan for Newly identified Automatic Reclosing Components due to generation changes in the Balancing Authority Area:~~For Sudden Pressure Relaying Component

~~This applies to PRC-005-3 and successor standards.~~

~~Additional applicable Automatic Reclosing Components may be identified because of the addition or retirement of generating units; or increases of gross generation capacity of individual generating units or plants within the Balancing Authority Area.~~

9. ~~In such cases, the responsible entities must complete the~~ maintenance activities~~, described~~ with maximum allowable intervals of twelve (12) calendar years, as established in Table ~~4, for~~5:

- The entity shall be at least 30% compliant on the ~~newly identified Automatic Reclosing Components prior to the end~~first day of the ~~third~~first calendar ~~year~~quarter sixty (60) months following ~~the identification of~~ applicable regulatory approval of PRC-005-X or, in those ~~Components unless documented prior maintenance fulfilling the requirements~~jurisdictions where no regulatory approval is required, on the first day of the first calendar quarter seventy-two (72) months following NERC Board of Trustees' adoption of PRC-005-X or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.
- The entity shall be at least 60% compliant on the first day of ~~Table 4 is available~~the first calendar quarter following one hundred eight (108) months following applicable regulatory approval of PRC-005-X or, in those jurisdictions where no regulatory approval is required, on the first day of the first calendar quarter one hundred twenty (120) months following NERC Board of Trustees' adoption of PRC-005-X or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.
- The entity shall be 100% compliant on the first day of the first calendar quarter one hundred fifty-six (156) months following applicable regulatory approval of PRC-005-X or, in those jurisdictions where no regulatory approval is required, on the first day of the first calendar quarter one hundred sixty-eight (168) months following NERC Board of Trustees' adoption of PRC-005-X or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

Applicability:

This standard applies to the following functional entities:

- Transmission Owner
- Generator Owner
- Distribution Provider
- Balancing Authority

Unofficial Comment Form

Project 2007-17.3 Protection System Maintenance and Testing – Phase 3 (Sudden Pressure Relays)

Please **DO NOT** use this form for submitting comments. Please use the electronic form to submit comments on the draft PER-005-2 standard. The electronic comment form must be completed by 8:00 p.m. ET on **Friday, June 2, 2014**.

If you have questions please contact Jordan Mallory via email or by telephone at 404-446-9733.

The project page may be accessed by clicking here.

Background Information

Project 2007-17.3 (PRC-005-X) will address a directive from FERC Order No. 758, which accepted NERC's proposal to develop a technical document, in lieu of a prescriptive FERC directive, that will provide the following information:

1) describe the devices and functions (to include sudden pressure relays which trip for fault conditions) that should address FERC's concern; and
2) propose minimum maintenance activities for such devices and maximum maintenance intervals, including the technical basis for each.

In Order No. 758, the Commission accepted NERC's proposal, by stating as follows:

> NERC states that these technical documents will address those protective relays that are necessary for the reliable operation of the Bulk-Power System and will allow for differentiation between protective relays that detect faults from other devices that monitor the health of the individual equipment and are advisory in nature (e.g., oil temperature). Following development of the above-referenced document(s), NERC states that it will "propose a new or revised standard (e.g. PRC-005) using the NERC Reliability Standards development process to include maintenance of such devices, including establishment of minimum maintenance activities and maximum maintenance intervals." Accordingly, NERC proposes to "add this issue to the Reliability Standards issues database for inclusion in the list of issues to address the next time the PRC-005 standard is revised."
>
> The Commission accepts NERC's proposal, and directs NERC to file, within sixty days of publication of this Final Rule, a schedule for informational purposes regarding the development of the technical documents referenced above, including the identification of devices that are designed to sense or take action against any abnormal system condition that will affect reliable operation. NERC shall include in the informational filing a schedule for the development of the changes to the standard

that NERC stated it would propose as a result of the above-referenced documents. NERC should update its schedule when it files its annual work plan.

As a follow-up to this Commission ruling, the Planning Committee studied sudden pressure relays and issued the attached report, which recommends moving ahead with a Standard. Specifically, the System Protection and Control Subcommittee (SPCS) completed a technical report recommending that a standard drafting team modify PRC-005 to explicitly address maintenance and testing of the actuator device of the sudden pressure relay when applied as a protective device that trips a facility described in the applicability section of the Reliability Standard. Additionally, the standard drafting team (SDT) intends to consider changes to the standard that provide consistency and alignment with other Reliability Standards. Lastly, the standards drafting team intends to modify the standard to address any directives issued by FERC related to the approval of PRC-005-3, which is pending filing with FERC.

PRC-005-X Revisions for draft 1:

The Standard Drafting Team has made several significant revisions to PRC-005-3 in establishing this draft of PRC-005-X.

1. In response to Order 758, the Standard Drafting Team (SDT) added Sudden Pressure Relaying by:
    a. Defining a new term
    b. Modified Protection System Maintenance Program (PSMP) definition to add Sudden Pressure Relaying
    c. Revising the Applicability elements
    d. Adding Table 5 to address minimum maintenance activities and maximum maintenance intervals
    e. Revising the previous Implementation Plan
2. The SDT reconsidered its position on including Balancing Authorities to PRC-005-4; therefore, the SDT:
    a. Added the Balancing Authority to the Applicability
    b. Added a requirement that Balancing Authorities notify their Transmission Owners, Generator Owners, and Distribution Providers of the largest BES generating unit within the Balancing Authority Area.
    c. Revised Requirements R3 and R4 to address the obligations previously expressed in the Implementation Plan regarding initial maintenance of Automatic Reclosing that becomes newly applicable at future times, and removed these elements from the Implementation Plan.
3. The SDT, seeing the concerns of the U.S. Office of Management and Budget and consulting with NERC Compliance Operations, reduced the required Data Retention.

4. The SDT made changes to the Supplementary Reference and FAQ Document to reflect the changes in the Standard.

Question

1. Do you have any comments regarding the addition of Sudden Pressure Relaying to PRC-005-X?

☐ Yes
☐ No

Comments:

2. Do you have any comments regarding the addition of Balancing Authority to PRC-005-X?

☐ Yes
☐ No

Comments:

3. Do you have any comments regarding the change in data retention to PRC-005-X?

☐ Yes
☐ No

Comments:

4. Do you have any comments regarding the changes made to the Supplementary Reference and FAQ Document to reflect the changes to PRC-005-X?

☐ Yes
☐ No

Comments:

5. Do you have any additional comments not addressed by one of the previous questions?

☐ Yes
☐ No

Comments:

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Supplementary Reference and FAQ

PRC-005-X Protection System Maintenance

April 2014

RELIABILITY | ACCOUNTABILITY

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1. Introduction and Summary

Note: This supplementary reference for PRC-005-X is neither mandatory nor enforceable.

NERC currently has four Reliability Standards that are mandatory and enforceable in the United States and Canada and address various aspects of maintenance and testing of Protection and Control Systems.

These standards are:

PRC-005-1b — Transmission and Generation Protection System Maintenance and Testing

PRC-008-0 — Underfrequency Load Shedding Equipment Maintenance Programs

PRC-011-0 — UVLS System Maintenance and Testing

PRC-017-0 — Special Protection System Maintenance and Testing

While these standards require that applicable entities have a maintenance program for Protection Systems, and that these entities must be able to demonstrate they are carrying out such a program, there are no specifics regarding the technical requirements for Protection System maintenance programs. Furthermore, FERC Order 693 directed additional modifications respective to Protection System maintenance programs. PRC-005-3 will replace PRC-005-2 which combined and replaced PRC-005, PRC-008, PRC-011 and PRC-017. PRC-005-3 adds Automatic Reclosing to PRC-005-2. PRC-005-2 addressed these directed modifications and replaces PRC-005, PRC-008, PRC-011 and PRC-017.

FERC Order 758 further directed that maintenance of reclosing relays and sudden pressure relays that affect the reliable operation of the Bulk Power System be addressed. PRC-005-3 addresses this directive regarding reclosing relays, and, when approved, will supersede PRC-005-2. PRC-005-X addresses this directive regarding sudden pressure relays and, when approved, will supersede PRC-005-3.

This document augments the Supplementary Reference and FAQ previously developed for PRC-005-2 by including discussion relevant to Automatic Reclosing added in PRC-005-3 and Sudden Pressure Relaying in PRC-005-X.

2. Need for Verifying Protection System Performance

Protective relays have been described as silent sentinels, and do not generally demonstrate their performance until a Fault or other power system problem requires that they operate to protect power system Elements, or even the entire Bulk Electric System (BES). Lacking Faults, switching operations or system problems, the Protection Systems may not operate, beyond static operation, for extended periods. A Misoperation - a false operation of a Protection System or a failure of the Protection System to operate, as designed, when needed - can result in equipment damage, personnel hazards, and wide-area Disturbances or unnecessary customer outages. Maintenance or testing programs are used to determine the performance and availability of Protection Systems.

Typically, utilities have tested Protection Systems at fixed time intervals, unless they had some incidental evidence that a particular Protection System was not behaving as expected. Testing practices vary widely across the industry. Testing has included system functionality, calibration of measuring devices, and correctness of settings. Typically, a Protection System must be visited at its installation site and, in many cases, removed from service for this testing.

Fundamentally, a Reliability Standard for Protection System Maintenance and Testing requires the performance of the maintenance activities that are necessary to detect and correct plausible age and service related degradation of the Protection System components, such that a properly built and commissioned Protection System will continue to function as designed over its service life.

Similarly station batteries, which are an important part of the station dc supply, are not called upon to provide instantaneous dc power to the Protection System until power is required by the Protection System to operate circuit breakers or interrupting devices to clear Faults or to isolate equipment.

2.1 Existing NERC Standards for Protection System Maintenance and Testing

For critical BES protection functions, NERC standards have required that each utility or asset owner define a testing program. The starting point is the existing Standard PRC-005, briefly restated as follows:

Purpose: To document and implement programs for the maintenance of all Protection Systems affecting the reliability of the Bulk Electric System (BES) so that these Protection Systems are kept in working order.

PRC-005-X is not specific on where the boundaries of the Protection Systems lie. However, the definition of Protection System in the NERC Glossary of Terms used in Reliability Standards indicates what must be included as a minimum.

At the beginning of the project to develop PRC-005-2, the definition of Protection System was:

Protective relays, associated communications Systems, voltage and current sensing devices, station batteries and dc control circuitry.

Applicability: Owners of generation and transmission Protection Systems.

Requirements: The owner shall have a documented maintenance program with test intervals. The owner must keep records showing that the maintenance was performed at the specified intervals.

2.2 Protection System Definition

The most recently approved definition of Protection Systems is:

- Protective relays which respond to electrical quantities,
- Communications systems necessary for correct operation of protective functions,
- Voltage and current sensing devices providing inputs to protective relays,
- Station dc supply associated with protective functions (including station batteries, battery chargers, and non-battery-based dc supply), and
- Control circuitry associated with protective functions through the trip coil(s) of the circuit breakers or other interrupting devices.

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:

"…that are installed for the purpose of detecting Faults on BES Elements (lines, buses, transformers, etc.)."

The drafting team intends that this standard will follow with any definition of the Bulk Electric System. There should be no ambiguity; if the Element is a BES Element, then the Protection System protecting that Element should then be included within this standard. If there is regional variation to the definition, then there will be a corresponding regional variation to the Protection Systems that fall under this standard.

There is no way for the Standard Drafting Team to know whether a specific 230KV line, 115KV line (even 69KV line), for example, should be included or excluded. Therefore, the team set the clear intent that the standard language should simply be applicable to Protection Systems for BES Elements.

The BES is a NERC defined term that, from time to time, may undergo revisions. Additionally, there may even be regional variations that are allowed in the present and future definitions. See the NERC Glossary of Terms for the present, in-force definition. See the applicable Regional Reliability Organization for any applicable allowed variations.

While this standard will undergo revisions in the future, this standard will not attempt to keep up with revisions to the NERC definition of BES, but, rather, simply make BES Protection Systems applicable.

The Standard is applied to Generator Owners (GO) and Transmission Owners (TO) because GOs and TOs have equipment that is BES equipment. The standard brings in Distribution Providers (DP) because, depending on the station configuration of a particular substation, there may be

Protection System equipment installed at a non-transmission voltage level (Distribution Provider equipment) that is wholly or partially installed to protect the BES. PRC-005-X would apply to this equipment. An example is underfrequency load-shedding, which is frequently applied well down into the distribution system to meet PRC-007-0.

PRC-005-2 replaced the existing PRC-005, PRC-008, PRC-011 and PRC-017. Much of the original intent of those standards was carried forward whenever it was possible to continue the intent without a disagreement with FERC Order 693. For example, the original PRC-008 was constructed quite differently than the original PRC-005. The drafting team agrees with the intent of this and notes that distributed tripping schemes would have to exhibit multiple failures to trip before they would prove to be significant, as opposed to a single failure to trip of, for example, a transmission Protection System Bus Differential lock-out relay. While many failures of these distribution breakers could add up to be significant, it is also believed that distribution breakers are operated often on just Fault clearing duty; and, therefore, the distribution circuit breakers are operated at least as frequently as stipulated in any requirement in this standard.

Additionally, since PRC-005-2 replaced PRC-011, it will be important to make the distinction between under-voltage Protection Systems that protect individual Loads and Protection Systems that are UVLS schemes that protect the BES. Any UVLS scheme that had been applicable under PRC-011 is now applicable under PRC-005-2. An example of an under-voltage load-shedding scheme that is not applicable to this standard is one in which the tripping action was intended to prevent low distribution voltage to a specific Load from a Transmission system that was intact except for the line that was out of service, as opposed to preventing a Cascading outage or Transmission system collapse.

It had been correctly noted that the devices needed for PRC-011 are the very same types of devices needed in PRC-005.

Thus, a standard written for Protection Systems of the BES can easily make the needed requirements for Protection Systems, and replace some other standards at the same time.

2.3.1 Frequently Asked Questions:

What exactly is the BES, or Bulk Electric System?

BES is the abbreviation for Bulk Electric System. BES is a term in the Glossary of Terms used in Reliability Standards, and is not being modified within this draft standard.
NERC's approved definition of Bulk Electric System is:

As defined by the Regional Reliability Organization, the electrical generation resources, transmission lines, Interconnections with neighboring Systems, and associated equipment, generally operated at voltages of 100 kV or higher. Radial transmission Facilities serving only Load with one transmission source are generally not included in this definition.

The BES definition is presently undergoing the process of revision.

Each regional entity implements a definition of the Bulk Electric System that is based on this NERC definition; in some cases, supplemented by additional criteria. These regional definitions have been documented and provided to FERC as part of a *June 14, 2007 Informational Filing*.

Why is Distribution Provider included within the Applicable Entities and as a responsible entity within several of the requirements? Wouldn't anyone having relevant Facilities be a Transmission Owner?

Depending on the station configuration of a particular substation, there may be Protection System equipment installed at a non-transmission voltage level (Distribution Provider equipment) that is wholly or partially installed to protect the BES. PRC-005-X applies to this equipment. An example is underfrequency load-shedding, which is frequently applied well down into the distribution system to meet PRC-007-0.

We have an under voltage load-shedding (UVLS) system in place that prevents one of our distribution substations from supplying extremely low voltage in the case of a specific transmission line outage. The transmission line is part of the BES. Does this mean that our UVLS system falls within this standard?

The situation, as stated, indicates that the tripping action was intended to prevent low distribution voltage to a specific Load from a Transmission System that was intact, except for the line that was out of service, as opposed to preventing Cascading outage or Transmission System Collapse.

This standard is not applicable to this UVLS.

We have a UFLS or UVLS scheme that sheds the necessary Load through distribution-side circuit breakers and circuit reclosers. Do the trip-test requirements for circuit breakers apply to our situation?

No. Distributed tripping schemes would have to exhibit multiple failures to trip before they would prove to be significant, as opposed to a single failure to trip of, for example, a transmission Protection System bus differential lock-out relay. While many failures of these distribution breakers could add up to be significant, it is also believed that distribution breakers are operated often on just Fault clearing duty; and, therefore, the distribution circuit breakers are operated at least as frequently as any requirements that might have appeared in this standard.

We have a UFLS scheme that, in some locales, sheds the necessary Load through non-BES circuit breakers and, occasionally, even circuit switchers. Do the trip-test requirements for circuit breakers apply to our situation?

If your "non-BES circuit breaker" has been brought into this standard by the inclusion of UFLS requirements, and otherwise would not have been brought into this standard, then the answer is that there are no trip-test requirements. For these devices that are otherwise non-BES assets, these tripping schemes would have to exhibit multiple failures to trip before they would prove to be as significant as, for example, a single failure to trip of a transmission Protection System bus differential lock-out relay.

How does the "Facilities" section of "Applicability" track with the standards that will be retired once PRC-005-2 becomes effective?

In establishing PRC-005-2, the drafting team combined legacy standards PRC-005-1b, PRC-008-0, PRC-011-0, and PRC-017-0. The merger of the subject matter of these standards is reflected in Applicability 4.2.

The intent of the drafting team is that the legacy standards be reflected in PRC-005-2 as follows:

- Applicability of PRC-005-1b for Protection Systems relating to non-generator elements of the BES is addressed in 4.2.1;
- Applicability of PRC-008-0 for underfrequency load shedding systems is addressed in 4.2.2;
- Applicability of PRC-011-0 for undervoltage load shedding relays is addressed in 4.2.3;
- Applicability of PRC-017-0 for Special Protection Systems is addressed in 4.2.4;
- Applicability of PRC-005-1b for Protection Systems for BES generators is addressed in 4.2.5.

2.4 Applicable Relays

The NERC Glossary definition has a Protection System including relays, dc supply, current and voltage sensing devices, dc control circuitry and associated communications circuits. The relays to which this standard applies are those protective relays that respond to electrical quantities and provide a trip output to trip coils, dc control circuitry or associated communications equipment. This definition extends to IEEE Device No. 86 (lockout relay) and IEEE Device No. 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.

Relays that respond to non-electrical inputs or impulses (such as, but not limited to, vibration, seismic, thermal or gas accumulation) are not included.

Automatic Reclosing is addressed in PRC-005-3 by explicitly addressing them outside the definition of Protection System. The specific locations for applicable Automatic Reclosing are addressed in Applicability Section 4.2.7.

Sudden Pressure Relaying is addressed in PRC-005-X by explicitly addressing them outside the definition of Protection System. The specific locations for applicable Sudden Pressure Relaying are addressed in Applicability Section 4.2.1, 4.2.5 and 4.2.6.

2.4.1 Frequently Asked Questions:

Are power circuit reclosers, reclosing relays, closing circuits and auto-restoration schemes covered in this Standard?

Yes. Automatic Reclosing includes reclosing relays and the associated dc control circuitry. Section 4.2.6 of the Applicability specifically limits the applicable reclosing relays to:

4.2.6 Automatic Reclosing

4.2.6.1 Automatic Reclosing applied on the terminals of Elements connected to the BES bus located at generating plant substations where the total installed gross generating plant capacity is greater than the gross capacity of the largest BES generating unit within the Balancing Authority Area.

4.2.6.2 Automatic Reclosing applied on the terminals of all BES Elements at substations one bus away from generating plants specified in Section 4.2.6.1 when the substation is less than 10 circuit-miles from the generating plant substation.

4.2.6.3 Automatic Reclosing applied as an integral part of a SPS specified in Section 4.2.4.

Further, Footnote 1 to Applicability Section 4.2.6 establishes that Automatic Reclosing addressed in 4.2.6.1 and 4.2.6.2 may be excluded if the equipment owner can demonstrate that a close-in three-phase fault present for twice the normal clearing time (capturing a minimum trip-close-trip time delay) does not result in a total loss of gross generation in the Interconnection exceeding the gross capacity of the largest BES unit within the Balancing Authority Area where the Automatic Reclosing is applied.

The Applicability as detailed above was recommended by the NERC System Analysis and Modeling Subcommittee (SAMS) after a lengthy review of the use of reclosing within the BES. SAMS concluded that automatic reclosing is largely implemented throughout the BES as an operating convenience, and that automatic reclosing mal-performance affects BES reliability only when the reclosing is part of a Special Protection System, or when premature autoreclosing has the potential to cause generating unit or plant instability. A technical report, “Considerations for Maintenance and Testing of Autoreclosing Schemes — November 2012”, is referenced in PRC-005-3 and provides a more detailed discussion of these concerns.

How do I interpret Applicability Section 4.2.6 to determine applicability in the following examples:

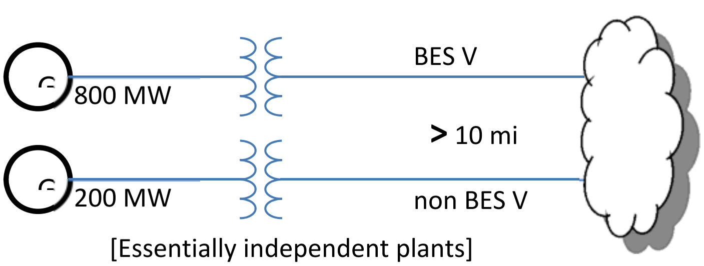
At my generating plant substation, I have a total of 800 MW connected to one voltage level and 200 MW connected to another voltage level. How do I determine my gross capacity? Where do I consider Automatic Reclosing to be applicable?

Scenario number 1:

The 800 MW of generation is connected to a BES voltage level bus, the 200 MW unit is connected to a non-BES voltage level bus, and there is no connection between the two buses locally or within 10 circuit miles from the generating plant substation. The largest single unit in the BA area is 750 MW.

In this case, the total installed gross generating capacity would be 800 MW. The two units are essentially independent plants.

The BES voltage level bus is considered to be the bus to which the 800 MW of generation is connected. Any BES Automatic Reclosing at this location, as well as other locations within 10 circuit miles, is considered to be applicable because 800 MW exceeds the largest single unit in the BA area.



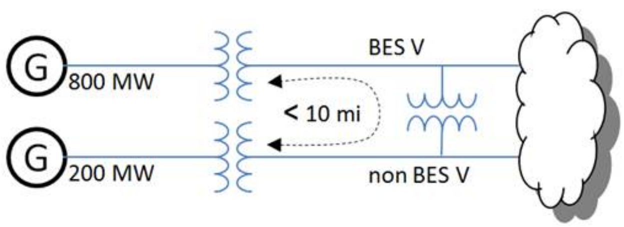
Gross Capacity	Automatic Reclosing in scope
800 MW	BES V

Scenario number 2:

The 800 MW of generation is connected to a BES voltage level bus, the 200 MW unit is connected to a non-BES voltage level bus, and there is a connection between the two buses locally or within 10 circuit miles from the generating plant substation. The largest single unit in the BA area is 750 MW.

In this case, reclosing into a fault on the BES system could impact the stability of the non-BES-connected generating units. Therefore, the total installed gross generating capacity would be 1000 MW.

The BES voltage level bus is considered to be the bus to which the 800 MW of generation is connected. Any BES Automatic Reclosing at this location, as well as other locations within 10 circuit miles, is considered to be applicable because total of 1000 MW exceeds the largest single unit in the BA area. However, the Automatic Reclosing on the non-BES voltage level bus is not applicable.



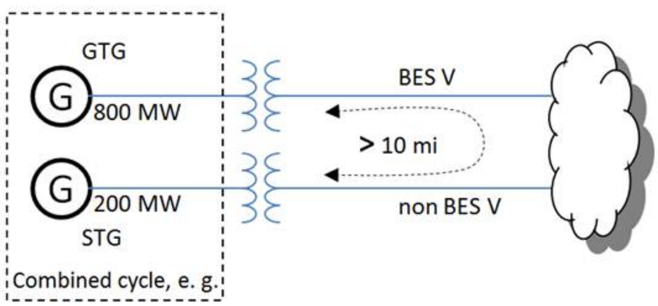
Gross Capacity	Automatic Reclosing in scope
1000 MW	BES V

Scenario number 3:

The 800 MW of generation is connected to a BES voltage level bus, the 200 MW unit is connected to a non-BES voltage level bus, and there is no connection between the two buses locally or within 10 circuit miles from the generating plant substation but the generating units connected at the BES voltage level do not operate independently of the units connected at the non BES voltage level (e.g., a combined cycle facility where 800 MW of combustion turbines are connected at a BES voltage level whose exhaust is used to power a 200 MW steam unit connected to a non BES voltage level. The largest single unit in the BA area is 750 MW.

In this case, the total installed gross generating capacity would be 1000 MW. Therefore, reclosing into a fault on the BES voltage level would result in a loss of the 800 MW combustion turbines and subsequently result in the loss of the 200 MW steam unit because of the loss of the heat source to its boiler.

The BES voltage level bus is considered to be the bus to which the 800 MW of generation is connected. Any BES Automatic Reclosing at this location, as well as other locations within 10 circuit miles, is considered to be applicable because total of 1000 MW exceeds the largest single unit in the BA area. However, the Automatic Reclosing on the non-BES voltage level bus is not applicable.



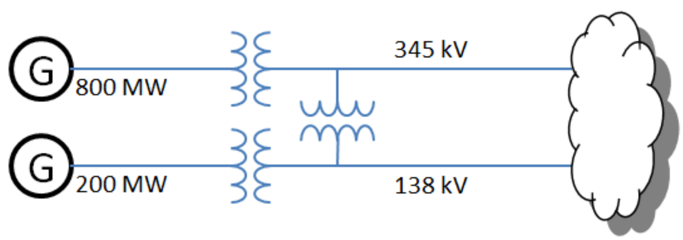
<u>**Gross Capacity**</u>	<u>**Automatic Reclosing in scope**</u>
1000 MW	BES V

Scenario 4

The 800 MW of generation is connected at 345 kV and the 200 MW is connected at 138 kV with an autotransformer at the generating plant substation connecting the two voltage levels. The largest single unit in the BA area is 900 MW.

In this case, the total installed gross generating capacity would be 1000 MW and section 4.2.6.1 would be applicable to both the 345 kV Automatic Reclosing Components and the 138 kV Automatic Reclosing Components, since the total capacity of 1000 MW is larger than the largest single unit in the BA area.

However, if the 345 kV and the 138 kV systems can be shown to be uncoupled such that the 138 kV reclosing relays will not affect the stability of the 345 kV generating units then the 138 kV Automatic Reclosing Components need not be included per section 4.2.6.1.



Gross Capacity	Automatic Reclosing in scope
1000 MW	BOTH*

* The study detailed in Footnote 1 of the draft standard may eliminate the 138 kV Automatic Reclosing Components and/or the 345 kV Automatic Reclosing Components

Why does 4.2.6.2 specify "10 circuit miles"?

As noted in "Considerations for Maintenance and Testing of Autoreclosing Schemes — November 2012", transmission line impedance on the order of one mile away typically provides adequate impedance to prevent generating unit instability and a 10 mile threshold provides sufficient margin.

Should I use MVA or MW when determining the installed gross generating plant capacity?

Be consistent with the rating used by the Balancing Authority for the largest BES generating unit within their area.

What value should we use for generating plant capacity in 4.2.6.1?

Use the value reported to the Balance Authority for generating plant capacity for planning and modeling purposes. This can be nameplate or other values based on generating plant limitations such as boiler or turbine ratings.

What is considered to be "one bus away" from the generation?

The BES voltage level bus is considered to be the generating plant substation bus to which the generator step-up transformer is connected. "One bus away" is the next bus, connected by either a transmission line or transformer.

I use my protective relays only as sources of metered quantities and breaker status for SCADA and EMS through a substation distributed RTU or data concentrator to the control center. What are the maintenance requirements for the relays?

This standard addresses Protection Systems that are installed for the purpose of detecting Faults on BES Elements (lines, buses, transformers, etc.). Protective relays, providing only the functions mentioned in the question, are not included.

Are Reverse Power Relays installed on the low-voltage side of distribution banks considered to be components of "Protection Systems that are installed for the purpose of detecting Faults on BES Elements (lines, buses, transformers, etc.)"?

Reverse power relays are often installed to detect situations where the transmission source becomes de-energized and the distribution bank remains energized from a source on the low-voltage side of the transformer and the settings are calculated based on the charging current of the transformer from the low-voltage side. Although these relays may operate as a result of a fault on a BES element, they are not 'installed for the purpose of detecting' these faults.

Why is the maintenance of Sudden Pressure Relaying being addressed in PRC-005-X?

Proper performance of Sudden Pressure Relaying supports the reliability of the BES because fault pressure relays can detect rapid changes in gas pressure, oil pressure, or oil flow that are indicative of faults within liquid-filled, wire-wound equipment such as turn-to-turn faults which may be undetected by Protection Systems. Additionally, Sudden Pressure Relaying can quickly detect faults and operate to limit damage to liquid-filled, wire-wound equipment.

What type of devices are classified as fault pressure relay?

There are three main types of fault pressure relays; rapid gas pressure rise, rapid oil pressure rise, and rapid oil flow devices.

Rapid gas pressure devices monitor the pressure in the space above the oil (or other liquid), and initiate tripping action for a rapid rise in gas pressure resulting from the rapid expansion of the liquid caused by a fault. The sensor is located in the gas space.

Rapid oil pressure devices monitor the pressure in the oil (or other liquid), and initiate tripping action for a rapid pressure rise caused by a fault. The sensor is located in the liquid.

Rapid oil flow devices ("Buchholz") monitor the liquid flow between a transformer/reactor and its conservator. Normal liquid flow occurs continuously with ambient temperature changes and with internal heating from loading and does not operate the rapid oil flow device. However, when an internal arc happens a sudden expansion of liquid can be monitored as rapid liquid flow from the transformer into the conservator resulting in actuation of the rapid oil flow device.

Are sudden pressure relays that only initiate an alarm included in the scope of PRC-005-X?

No, the definition of Sudden Pressure Relaying specifies only those that trip an interrupting device(s) to isolate the equipment it is monitoring.

Is Sudden Pressure Relaying installed on distribution transformers included in PRC-005-X?

No, Applicability 4.2.1, 4.2.5.2, 4.2.5.3, 4.2.6.1, explicitly describe what Sudden Pressure Relaying is included within the standard.

Are non-electrical sensing devices (other than fault pressure relays) such as as low oil level or high winding temperatures included in PRC-005-X?

No, based on the SPCS technical document, "Sudden Pressure Relays and Other Devices that Respond to Non-Electrical Quantities – December 2013" the only applicable non-electrical sensing devices are fault pressure relays.

The standard specifically mentions auxiliary and lock-out relays. What is an auxiliary tripping relay?

An auxiliary relay, IEEE Device No. 94, is described in IEEE Standard C37.2-2008 as: "A device that functions to trip a circuit breaker, contactor, or equipment; to permit immediate tripping by other devices; or to prevent immediate reclosing of a circuit interrupter if it should open automatically, even though its closing circuit is maintained closed."

What is a lock-out relay?

A lock-out relay, IEEE Device No. 86, is described in IEEE Standard C37.2 as: "A device that trips and maintains the associated equipment or devices inoperative until it is reset by an operator, either locally or remotely."

3. Protection System and Automatic Reclosing Product Generations

The likelihood of failure and the ability to observe the operational state of a critical Protection System and Automatic Reclosing both depend on the technological generation of the relays, as well as how long they have been in service. Unlike many other transmission asset groups, protection and control systems have seen dramatic technological changes spanning several generations. During the past 20 years, major functional advances are primarily due to the introduction of microprocessor technology for power system devices, such as primary measuring relays, monitoring devices, control Systems, and telecommunications equipment.

Modern microprocessor-based relays have six significant traits that impact a maintenance strategy:

- Self-monitoring capability - the processors can check themselves, peripheral circuits, and some connected substation inputs and outputs, such as trip coil continuity. Most relay users are aware that these relays have self-monitoring, but are not focusing on exactly what internal functions are actually being monitored. As explained further below, every element critical to the Protection System must be monitored, or else verified periodically.
- Ability to capture Fault records showing how the Protection System responded to a Fault in its zone of protection, or to a nearby Fault for which it is required not to operate.
- Ability to meter currents and voltages, as well as status of connected circuit breakers, continuously during non-Fault times. The relays can compute values, such as MW and MVAR line flows, that are sometimes used for operational purposes, such as SCADA.
- Data communications via ports that provide remote access to all of the results of Protection System monitoring, recording and measurement.
- Ability to trip or close circuit breakers and switches through the Protection System outputs, on command from remote data communications messages, or from relay front panel button requests.
- Construction from electronic components, some of which have shorter technical life or service life than electromechanical components of prior Protection System generations.

There have been significant advances in the technology behind the other components of Protection Systems. Microprocessors are now a part of battery chargers, associated communications equipment, voltage and current-measuring devices, and even the control circuitry (in the form of software-latches replacing lock-out relays, etc.).

Any Protection System component can have self-monitoring and alarming capability, not just relays. Because of this technology, extended time intervals can find their way into all components of the Protection System.

This standard also recognizes the distinct advantage of using advanced technology to justifiably defer or even eliminate traditional maintenance. Just as a hand-held calculator does not require routine testing and calibration, neither does a calculation buried in a microprocessor-based device that results in a “lock-out.” Thus, the software-latch 86 that replaces an electro-mechanical 86 does not require routine trip testing. Any trip circuitry associated with the “soft 86” would still need applicable verification activities performed, but the actual “86” does not have to be “electrically operated” or even toggled.

4. Definitions

Protection System Maintenance Program (PSMP) — An ongoing program by which Protection System, Automatic Reclosing and Sudden Pressure Relaying Components are kept in working order and proper operation of malfunctioning Components is restored. A maintenance program for a specific Component includes one or more of the following activities:

- Verify — Determine that the Component is functioning correctly.
- Monitor — Observe the routine in-service operation of the Component.
- Test — Apply signals to a Component to observe functional performance or output behavior, or to diagnose problems.
- Inspect — Detect visible signs of Component failure, reduced performance and degradation.
- Calibrate — Adjust the operating threshold or measurement accuracy of a measuring element to meet the intended performance requirement.

Automatic Reclosing – Includes the following Components:

- Reclosing relay
- Control circuitry associated with the reclosing relay.

Sudden Pressure Relaying – A system that trips an interrupting device(s) to isolate the equipment it is monitoring and includes the following Components:

- Fault pressure relay – a mechanical relay or device that detecting rapid changes in gas pressure, oil pressure, or oil flow that are indicative of faults within liquid-filled, wire-wound equipment
- Control circuitry associated with a fault pressure relay

Unresolved Maintenance Issue – A deficiency identified during a maintenance activity that causes the component to not meet the intended performance, cannot be corrected during the maintenance interval, and requires follow-up corrective action.

Segment – Components of a consistent design standard, or a particular model or type from a single manufacturer that typically share other common elements. Consistent performance is expected across the entire population of a Segment. A Segment must contain at least sixty (60) individual Components.

Component Type –

- Any one of the five specific elements of a Protection System.
- Any one of the two specific elements of Automatic Reclosing.
- Any one of the two specific elements of Sudden Pressure Relaying.

Component – Any individual discrete piece of equipment included in a Protection System, Automatic Reclosing, or Sudden Pressure Relaying.

Countable Event – A failure of a Component requiring repair or replacement, any condition discovered during the maintenance activities in Tables 1-1 through 1-5, Table 3, Tables 4-1 through 4-2, and Table 5, which requires corrective action or a Protection System Misoperation attributed to hardware failure or calibration failure. Misoperations due to product design errors, software errors, relay settings different from specified settings, Protection System Component, Automatic Reclosing or Sudden Pressure Relaying configuration or application errors are not included in Countable Events.

4.1 Frequently Asked Questions:

Why does PRC-005-X not specifically require maintenance and testing procedures, as reflected in the previous standard, PRC-005-1?

PRC-005-1 does not require detailed maintenance and testing procedures, but instead requires summaries of such procedures, and is not clear on what is actually required. PRC-005-X requires a documented maintenance program, and is focused on establishing requirements rather than prescribing methodology to meet those requirements. Between the activities identified in the Tables 1-1 through 1-5, Table 2, Table 3, and Table 4 (collectively the "Tables"), and the various components of the definition established for a "Protection System Maintenance Program," PRC-005-X establishes the activities and time basis for a Protection System Maintenance Program to a level of detail not previously required.

Please clarify what is meant by "restore" in the definition of maintenance.

The description of "restore" in the definition of a Protection System Maintenance Program addresses corrective activities necessary to assure that the component is returned to working order following the discovery of its failure or malfunction. The Maintenance Activities specified in the Tables do not present any requirements related to Restoration; R5 of the standard does require that the entity "shall demonstrate efforts to correct any identified Unresolved Maintenance Issues." Some examples of restoration (or correction of Unresolved Maintenance Issues) include, but are not limited to, replacement of capacitors in distance relays to bring them to working order; replacement of relays, or other Protection System components, to bring the Protection System to working order; upgrade of electromechanical or solid-state protective relays to microprocessor-based relays following the discovery of failed components. Restoration, as used in this context, is not to be confused with restoration rules as used in system operations. Maintenance activity necessarily includes both the detection of problems and the repairs needed to eliminate those problems. This standard does not identify all of the Protection System problems that must be detected and eliminated, rather it is the intent of this standard that an entity determines the necessary working order for their various devices, and keeps them in working order. If an equipment item is repaired or replaced, then the entity can restart the maintenance-time-interval-clock, if desired; however, the replacement of equipment does not remove any documentation requirements that would have been required to verify compliance with time-interval requirements. In other words, do not discard maintenance data that goes to verify your work.

The retention of documentation for new and/or replaced equipment is all about proving that the maintenance intervals had been in compliance. For example, a long-range plan of upgrades might lead an entity to ignore required maintenance; retaining the evidence of prior maintenance that existed before any retirements and upgrades proves compliance with the standard.

Please clarify what is meant by "...demonstrate efforts to correct an Unresolved Maintenance Issue..."; why not measure the completion of the corrective action?

Management of completion of the identified Unresolved Maintenance Issue is a complex topic that falls outside of the scope of this standard. There can be any number of supply, process and management problems that make setting repair deadlines impossible. The SDT specifically chose the phrase "demonstrate efforts to correct" (with guidance from NERC Staff) because of the concern that many more complex Unresolved Maintenance Issues might require greater than the remaining maintenance interval to resolve (and yet still be a "closed-end process"). For example, a problem might be identified on a VRLA battery during a six-month check. In instances such as one that requiring battery replacement as part of the long-term resolution, it is highly unlikely that the battery could be replaced in time to meet the six-calendar-month requirement for this maintenance activity. The SDT does not believe entities should be found in violation of a maintenance program requirement because of the inability to complete a remediation program within the original maintenance interval. The SDT does believe corrective actions should be timely, but concludes it would be impossible to postulate all possible remediation projects; and, therefore, impossible to specify bounding time frames for resolution of all possible Unresolved Maintenance Issues, or what documentation might be sufficient to provide proof that effective corrective action is being undertaken.

5. Time-Based Maintenance (TBM) Programs

Time-based maintenance is the process in which Protection System, Automatic Reclosing and Sudden Pressure Relaying Components are maintained or verified according to a time schedule. The scheduled program often calls for technicians to travel to the physical site and perform a functional test on Protection System components. However, some components of a TBM program may be conducted from a remote location - for example, tripping a circuit breaker by communicating a trip command to a microprocessor relay to determine if the entire Protection System tripping chain is able to operate the breaker. Similarly, all Protection System, and Sudden Pressure Relaying Components can have the ability to remotely conduct tests, either on-command or routinely; the running of these tests can extend the time interval between hands-on maintenance activities.

5.1 Maintenance Practices

Maintenance and testing programs often incorporate the following types of maintenance practices:

- TBM – time-based maintenance – externally prescribed maximum maintenance or testing intervals are applied for components or groups of components. The intervals may have been developed from prior experience or manufacturers' recommendations. The TBM verification interval is based on a variety of factors, including experience of the particular asset owner, collective experiences of several asset owners who are members of a country or regional council, etc. The maintenance intervals are fixed and may range in number of months or in years.

  TBM can include review of recent power system events near the particular terminal. Operating records may verify that some portion of the Protection System has operated correctly since the last test occurred. If specific protection scheme components have demonstrated correct performance within specifications, the maintenance test time clock can be reset for those components.

- PBM – Performance-Based Maintenance - intervals are established based on analytical or historical results of TBM failure rates on a statistically significant population of similar components. Some level of TBM is generally followed. Statistical analyses accompanied by adjustments to maintenance intervals are used to justify continued use of PBM-developed extended intervals when test failures or in-service failures occur infrequently.

- CBM – condition-based maintenance – continuously or frequently reported results from non-disruptive self-monitoring of components demonstrate operational status as those components remain in service. Whatever is verified by CBM does not require manual testing, but taking advantage of this requires precise technical focus on exactly what parts are included as part of the self-diagnostics. While the term "Condition-Based-Maintenance" (CBM) is no longer used within the standard itself, it is important to note that the concepts of CBM are a part of the standard (in the form of extended time intervals through status-monitoring). These extended time intervals are only allowed (in the absence of PBM) if the condition of the device is monitored (CBM). As a consequence of the "monitored-basis-time-intervals" existing within the standard, the explanatory

discussions within this Supplementary Reference concerned with CBM will remain in this reference and are discussed as CBM.

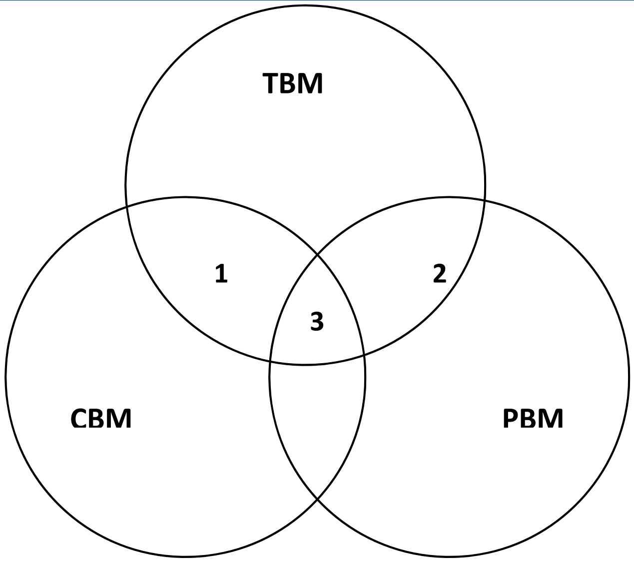
Microprocessor-based Protection System or Automatic Reclosing Components that perform continuous self-monitoring verify correct operation of most components within the device. Self-monitoring capabilities may include battery continuity, float voltages, unintentional grounds, the ac signal inputs to a relay, analog measuring circuits, processors and memory for measurement, protection, and data communications, trip circuit monitoring, and protection or data communications signals (and many, many more measurements). For those conditions, failure of a self-monitoring routine generates an alarm and may inhibit operation to avoid false trips. When internal components, such as critical output relay contacts, are not equipped with self-monitoring, they can be manually tested. The method of testing may be local or remote, or through inherent performance of the scheme during a system event.

The TBM is the overarching maintenance process of which the other types are subsets. Unlike TBM, PBM intervals are adjusted based on good or bad experiences. The CBM verification intervals can be hours, or even milliseconds between non-disruptive self-monitoring checks within or around components as they remain in service.

TBM, PBM, and CBM can be combined for individual components, or within a complete Protection System. The following diagram illustrates the relationship between various types of maintenance practices described in this section. In the Venn diagram, the overlapping regions show the relationship of TBM with PBM historical information and the inherent continuous monitoring offered through CBM.

This figure shows:

- Region 1: The TBM intervals that are increased based on known reported operational condition of individual components that are monitoring themselves.
- Region 2: The TBM intervals that are adjusted up or down based on results of analysis of maintenance history of statistically significant population of similar products that have been subject to TBM.
- Region 3: Optimal TBM intervals based on regions 1 and 2.



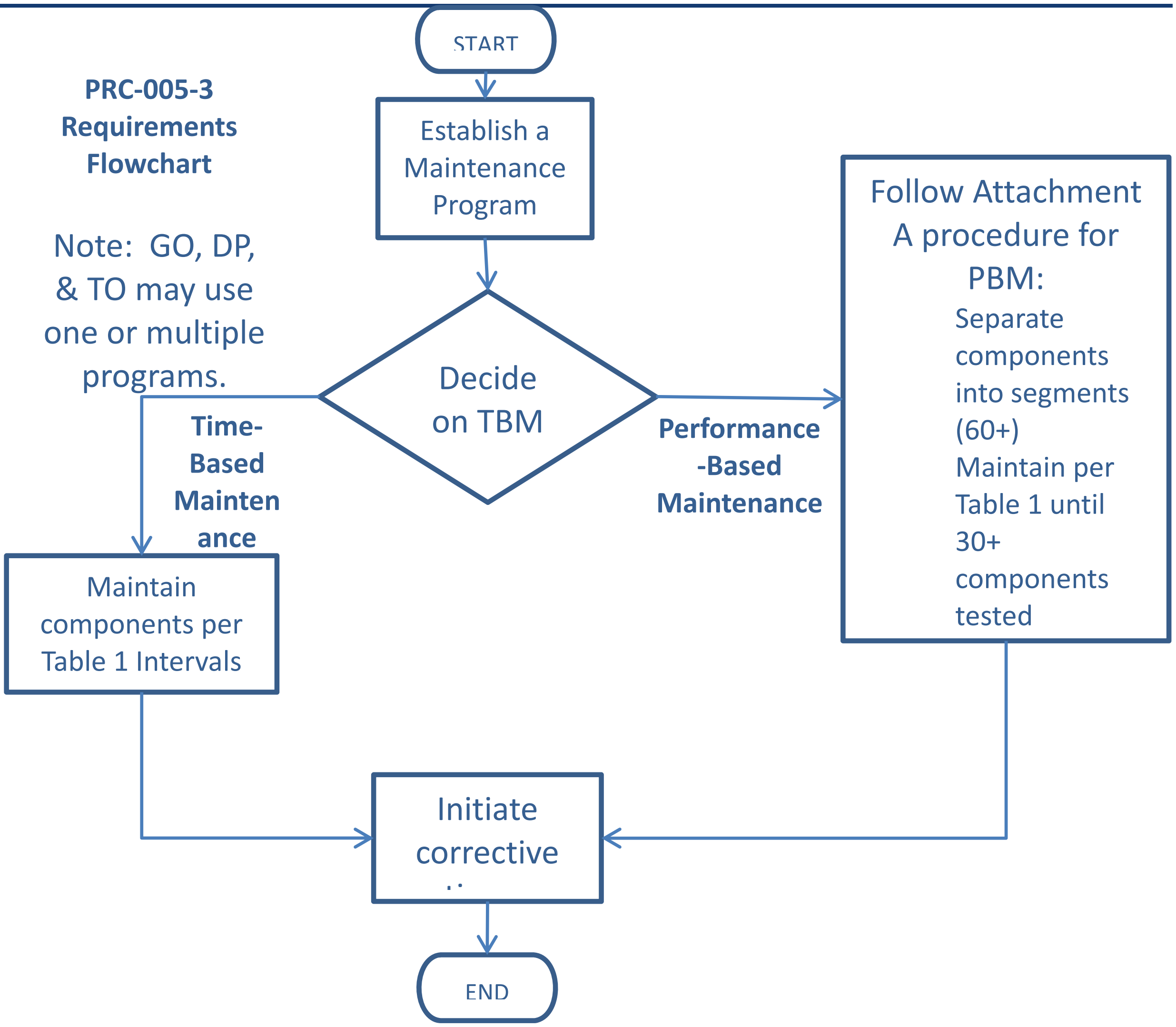
Relationship of time-based maintenance types

5.1.1 Frequently Asked Questions:

The standard seems very complicated, and is difficult to understand. Can it be simplified?

Because the standard is establishing parameters for condition-based Maintenance (R1) and Performance-Based Maintenance (R2), in addition to simple time-based Maintenance, it does appear to be complicated. At its simplest, an entity needs to ONLY perform time-based maintenance according to the unmonitored rows of the Tables. If an entity then wishes to take advantage of monitoring on its Protection System components and its available lengthened time intervals, then it may, as long as the component has the listed monitoring attributes. If an entity wishes to use historical performance of its Protection System components to perform Performance-Based Maintenance, then R2 applies.

Please see the following diagram, which provides a “flow chart” of the standard.



We have an electromechanical (unmonitored) relay that has a trip output to a lockout relay (unmonitored) which trips our transformer off-line by tripping the transformer's high-side and low-side circuit breakers. What testing must be done for this system?

This system is made up of components that are all unmonitored. Assuming a time-based Protection System Maintenance Program schedule (as opposed to a Performance-Based maintenance program), each component must be maintained per the most frequent hands-on activities listed in the Tables.

5.2 Extending Time-Based Maintenance

All maintenance is fundamentally time-based. Default time-based intervals are commonly established to assure proper functioning of each component of the Protection System, when data on the reliability of the components is not available other than observations from time-based maintenance. The following factors may influence the established default intervals:

- If continuous indication of the functional condition of a component is available (from relays or chargers or any self-monitoring device), then the intervals may be extended, or manual testing may be eliminated. This is referred to as condition-based maintenance or

CBM. CBM is valid only for precisely the components subject to monitoring. In the case of microprocessor-based relays, self-monitoring may not include automated diagnostics of every component within a microprocessor.

- Previous maintenance history for a group of components of a common type may indicate that the maintenance intervals can be extended, while still achieving the desired level of performance. This is referred to as Performance-Based Maintenance, or PBM. It is also sometimes referred to as reliability-centered maintenance, or RCM; but PBM is used in this document.
- Observed proper operation of a component may be regarded as a maintenance verification of the respective component or element in a microprocessor-based device. For such an observation, the maintenance interval may be reset only to the degree that can be verified by data available on the operation. For example, the trip of an electromechanical relay for a Fault verifies the trip contact and trip path, but only through the relays in series that actually operated; one operation of this relay cannot verify correct calibration.

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. The improper application of test signals may cause failure of a component. For example, in electromechanical overcurrent relays, test currents have been known to destroy convolution springs.

In addition, maintenance usually takes the component out of service, during which time it is not able to perform its function. Cutout switch failures, or failure to restore switch position, commonly lead to protection failures.

5.2.1 Frequently Asked Questions:

If I show the protective device out of service while it is being repaired, then can I add it back as a new protective device when it returns? If not, my relay testing history would show that I was out of compliance for the last maintenance cycle.

The maintenance and testing requirements (R5) (in essence) state "…shall demonstrate efforts to correct any identified Unresolved Maintenance Issues." The type of corrective activity is not stated; however it could include repairs or replacements.

Your documentation requirements will increase, of course, to demonstrate that your device tested bad and had corrective actions initiated. Your regional entity could very well ask for documentation showing status of your corrective actions.

6. Condition-Based Maintenance (CBM) Programs

Condition-based maintenance is the process of gathering and monitoring the information available from modern microprocessor-based relays and other intelligent electronic devices (IEDs) that monitor Protection System or Automatic Reclosing elements. These devices generate monitoring information during normal operation, and the information can be assessed at a convenient location remote from the substation. The information from these relays and IEDs is divided into two basic types:

1. Information can come from background self-monitoring processes, programmed by the manufacturer, or by the user in device logic settings. The results are presented by alarm contacts or points, front panel indications, and by data communications messages.
2. Information can come from event logs, captured files, and/or oscillographic records for Faults and Disturbances, metered values, and binary input status reports. Some of these are available on the device front panel display, but may be available via data communications ports. Large files of Fault information can only be retrieved via data communications. These results comprise a mass of data that must be further analyzed for evidence of the operational condition of the Protection System.

Using these two types of information, the user can develop an effective maintenance program carried out mostly from a central location remote from the substation. This approach offers the following advantages:

> **Non-invasive Maintenance:** The system is kept in its normal operating state, without human intervention for checking. This reduces risk of damage, or risk of leaving the system in an inoperable state after a manual test. Experience has shown that keeping human hands away from equipment known to be working correctly enhances reliability.
>
> **Virtually Continuous Monitoring:** CBM will report many hardware failure problems for repair within seconds or minutes of when they happen. This reduces the percentage of problems that are discovered through incorrect relaying performance. By contrast, a hardware failure discovered by TBM may have been there for much of the time interval between tests, and there is a good chance that some devices will show health problems by incorrect operation before being caught in the next test round. The frequent or continuous nature of CBM makes the effective verification interval far shorter than any required TBM maximum interval. To use the extended time intervals available through Condition Based Maintenance, simply look for the rows in the Tables that refer to monitored items.

6.1 Frequently Asked Questions:

My microprocessor relays and dc circuit alarms are contained on relay panels in a 24-hour attended control room. Does this qualify as an extended time interval condition-based (monitored) system?

Yes, provided the station attendant (plant operator, etc.) monitors the alarms and other indications (comparable to the monitoring attributes) and reports them within the given time limits that are stated in the criteria of the Tables.

When documenting the basis for inclusion of components into the appropriate levels of monitoring, as per Requirement R1 (Part 1.4) of the standard, is it necessary to provide this documentation about the device by listing of every component and the specific monitoring attributes of each device?

No. While maintaining this documentation on the device level would certainly be permissible, it is not necessary. Global statements can be made to document appropriate levels of monitoring for the entire population of a component type or portion thereof.

For example, it would be permissible to document the conclusion that all BES substation dc supply battery chargers are monitored by stating the following within the program description:

> "All substation dc supply battery chargers are considered monitored and subject to the rows for monitored equipment of Table 1-4 requirements, as all substation dc supply battery chargers are equipped with dc voltage alarms and ground detection alarms that are sent to the manned control center."

Similarly, it would be acceptable to use a combination of a global statement and a device-level list of exclusions. Example:

> "Except as noted below, all substation dc supply battery chargers are considered monitored and subject to the rows for monitored equipment of Table 1-4 requirements, as all substation dc supply battery chargers are equipped with dc voltage alarms and ground detection alarms that are sent to the manned control center. The dc supply battery chargers of Substation X, Substation Y, and Substation Z are considered unmonitored and subject to the rows for unmonitored equipment in Table 1-4 requirements, as they are not equipped with ground detection capability."

Regardless whether this documentation is provided by device listing of monitoring attributes, by global statements of the monitoring attributes of an entire population of component types, or by some combination of these methods, it should be noted that auditors may request supporting drawings or other documentation necessary to validate the inclusion of the device(s) within the appropriate level of monitoring. This supporting background information need not be maintained within the program document structure, but should be retrievable if requested by an auditor.

7. Time-Based Versus Condition-Based Maintenance

Time-based and condition-based (or monitored) maintenance programs are both acceptable, if implemented according to technically sound requirements. Practical programs can employ a *combination of time-based and condition-based maintenance.* The standard requirements introduce the concept of optionally using condition monitoring as a documented element of a maintenance program.

The Federal Energy Regulatory Commission (FERC), in its Order Number 693 Final Rule, dated March 16, 2007 (18 CFR Part 40, Docket No. RM06-16-000) on Mandatory Reliability Standards for the Bulk-Power System, directed NERC to submit a modification to PRC-005-1b that includes a requirement that maintenance and testing of a Protection System must be carried out within a maximum allowable interval that is appropriate to the type of the Protection System and its impact on the reliability of the Bulk Power System. Accordingly, this Supplementary Reference Paper refers to the specific maximum allowable intervals in PRC-005-X. The defined time limits allow for longer time intervals if the maintained component is monitored.

A key feature of condition-based monitoring is that it effectively reduces the time delay between the moment of a protection failure and time the Protection System or Automatic Reclosing owner knows about it, for the monitored segments of the Protection System. In some cases, the verification is practically continuous - the time interval between verifications is minutes or seconds. Thus, technically sound, condition-based verification, meets the verification requirements of the FERC order even more effectively than the strictly time-based tests of the same system components.

The result is that:

This NERC standard permits utilities to use a technically sound approach and to take advantage of remote monitoring, data analysis, and control capabilities of modern Protection System and Automatic Reclosing Components to reduce the need for periodic site visits and invasive testing of components by on-site technicians. This periodic testing must be conducted within the maximum time intervals specified in the Tables of PRC-005-X.

7.1 Frequently Asked Questions:

What is a Calendar Year?

Calendar Year - January 1 through December 31 of any year. As an example, if an event occurred on June 17, 2009 and is on a "One Calendar Year Interval," the next event would have to occur on or before December 31, 2010.

Please provide an example of "4 Calendar Months".

If a maintenance activity is described as being needed every four Calendar Months then it is performed in a (given) month and due again four months later. For example a battery bank is inspected in month number 1 then it is due again before the end of the month number5. And specifically consider that you perform your battery inspection on January 3, 2010 then it must be inspected again before the end of May. Another example could be that a four-month inspection

was performed in January is due in May, but if performed in March (instead of May) would still be due four months later therefore the activity is due again July. Basically every "four Calendar Months" means to add four months from the last time the activity was performed.

Please provide an example of the unmonitored versus other levels of monitoring available?

An unmonitored Protection System has no monitoring and alarm circuits on the Protection System components. A Protection System component that has monitoring attributes but no alarm output connected is considered to be unmonitored.

A monitored Protection System or an individual monitored component of a Protection System has monitoring and alarm circuits on the Protection System components. The alarm circuits must alert, within 24 hours, a location wherein corrective action can be initiated. This location might be, but is not limited to, an Operations Center, Dispatch Office, Maintenance Center or even a portable SCADA system.

There can be a combination of monitored and unmonitored Protection Systems within any given scheme, substation or plant; there can also be a combination of monitored and unmonitored components within any given Protection System.

Example #1: A combination of monitored and unmonitored components within a given Protection System might be:

- A microprocessor relay with an internal alarm connected to SCADA to alert 24-hr staffed operations center; it has internal self-diagnosis and alarming. (monitored)
- Instrumentation transformers, with no monitoring, connected as inputs to that relay. (unmonitored)
- A vented Lead-Acid battery with a low voltage alarm for the station dc supply voltage and an unintentional grounds detection alarm connected to SCADA. (monitoring varies)
- A circuit breaker with a trip coil, and the trip circuit is not monitored. (unmonitored)

Given the particular components and conditions, and using Table 1 and Table 2, the particular components have maximum activity intervals of:

Every four calendar months, inspect:

- Electrolyte level (station dc supply voltage and unintentional ground detection is being maintained more frequently by the monitoring system).

Every 18 calendar months, verify/inspect the following:

- Battery bank ohmic values to station battery baseline (if performance tests are not opted)
- Battery charger float voltage
- Battery rack integrity
- Cell condition of all individual battery cells (where visible)
- Battery continuity
- Battery terminal connection resistance

- Battery cell-to-cell resistance (where available to measure)

<u>Every six calendar years</u>, perform/verify the following:

- Battery performance test (if internal ohmic tests or other measurements indicative of battery performance are not opted)
- Verify that each trip coil is able to operate the circuit breaker, interrupting device, or mitigating device
- For electromechanical lock-out relays, electrical operation of electromechanical trip

<u>Every 12 calendar years</u>, verify the following:

- Microprocessor relay settings are as specified
- Operation of the microprocessor's relay inputs and outputs that are essential to proper functioning of the Protection System
- Acceptable measurement of power System input values seen by the microprocessor protective relay
- Verify that current and voltage signal values are provided to the protective relays
- Protection System component monitoring for the battery system signals are conveyed to a location where corrective action can be initiated
- The microprocessor relay alarm signals are conveyed to a location where corrective action can be initiated
- Verify all trip paths in the control circuitry associated with protective functions through the trip coil(s) of the circuit breakers or other interrupting devices
- Auxiliary outputs that are in the trip path shall be maintained as detailed in Table 1-5 of the standard under the 'Unmonitored Control Circuitry Associated with Protective Functions" section'
- Auxiliary outputs not in a trip path (i.e., annunciation or DME input) are not required, by this standard, to be checked

Example #2: A combination of monitored and unmonitored components within a given Protection System might be:

- A microprocessor relay with integral alarm that is not connected to SCADA. (unmonitored)
- Current and voltage signal values, with no monitoring, connected as inputs to that relay. (unmonitored)
- A vented lead-acid battery with a low voltage alarm for the station dc supply voltage and an unintentional grounds detection alarm connected to SCADA. (monitoring varies)
- A circuit breaker with a trip coil, with no circuits monitored. (unmonitored)

Given the particular components and conditions, and using the Table 1 (Maximum Allowable Testing Intervals and Maintenance Activities) and Table 2 (Alarming Paths and Monitoring), the particular components have maximum activity intervals of:

Every four calendar months, inspect:

- Electrolyte level (station dc supply voltage and unintentional ground detection is being maintained more frequently by the monitoring system)

Every 18 calendar months, verify/inspect the following:

- Battery bank trending of ohmic values or other measurements indicative of battery performance to station battery baseline (if performance tests are not opted)
- Battery charger float voltage
- Battery rack integrity
- Cell condition of all individual battery cells (where visible)
- Battery continuity
- Battery terminal connection resistance
- Battery cell-to-cell resistance (where available to measure)

Every six calendar years, verify/perform the following:

- Verify operation of the relay inputs and outputs that are essential to proper functioning of the Protection System
- Verify acceptable measurement of power system input values as seen by the relays
- Verify that each trip coil is able to operate the circuit breaker, interrupting device, or mitigating device
- For electromechanical lock-out relays, electrical operation of electromechanical trip
- Battery performance test (if internal ohmic tests are not opted)

Every 12 calendar years, verify the following:

- Current and voltage signal values are provided to the protective relays
- Protection System component monitoring for the battery system signals are conveyed to a location where corrective action can be initiated
- All trip paths in the control circuitry associated with protective functions through the trip coil(s) of the circuit breakers or other interrupting devices
- Auxiliary outputs that are in the trip path shall be maintained, as detailed in Table 1-5 of the standard under the Unmonitored Control Circuitry Associated with Protective Functions" section
- Auxiliary outputs not in a trip path (i.e., annunciation or DME input) are not required, by this standard, to be checked

Example #3: A combination of monitored and unmonitored components within a given Protection System might be:

- A microprocessor relay with alarm connected to SCADA to alert 24-hr staffed operations center; it has internal self-diagnosis and alarms. (monitored)
- Current and voltage signal values, with monitoring, connected as inputs to that relay (monitored)

- Vented Lead-Acid battery without any alarms connected to SCADA (unmonitored)
- Circuit breaker with a trip coil, with no circuits monitored (unmonitored)

Given the particular components, conditions, and using the Table 1 (Maximum Allowable Testing Intervals and Maintenance Activities) and Table 2 (Alarming Paths and Monitoring), the particular components shall have maximum activity intervals of:

Every four calendar months, verify/inspect the following:

- Station dc supply voltage
- For unintentional grounds
- Electrolyte level

Every 18 calendar months, verify/inspect the following:

- Battery bank trending of ohmic values or other measurements indicative of battery performance to station battery baseline (if performance tests are not opted)
- Battery charger float voltage
- Battery rack integrity
- Battery continuity
- Battery terminal connection resistance
- Battery cell-to-cell resistance (where available to measure)
- Condition of all individual battery cells (where visible)

Every six calendar years, perform/verify the following:

- Battery performance test (if internal ohmic tests or other measurements indicative of battery performance are not opted)
- Verify that each trip coil is able to operate the circuit breaker, interrupting device, or mitigating device
- For electromechanical lock-out relays, electrical operation of electromechanical trip

Every 12 calendar years, verify the following:

- The microprocessor relay alarm signals are conveyed to a location where corrective action can be taken
- Microprocessor relay settings are as specified
- Operation of the microprocessor's relay inputs and outputs that are essential to proper functioning of the Protection System
- Acceptable measurement of power system input values seen by the microprocessor protective relay
- Verify all trip paths in the control circuitry associated with protective functions through the trip coil(s) of the circuit breakers or other interrupting devices

- Auxiliary outputs that are in the trip path shall be maintained, as detailed in Table 1-5 of the standard under the Unmonitored Control Circuitry Associated with Protective Functions section
- Auxiliary outputs not in a trip path (i.e. annunciation or DME input) are not required, by this standard, to be checked

Why do components have different maintenance activities and intervals if they are monitored?

The intent behind different activities and intervals for monitored equipment is to allow less frequent manual intervention when more information is known about the condition of Protection System components. Condition-Based Maintenance is a valuable asset to improve reliability.

Can all components in a Protection System be monitored?

No. For some components in a Protection System, monitoring will not be relevant. For example, a battery will always need some kind of inspection.

We have a 30-year-old oil circuit breaker with a red indicating lamp on the substation relay panel that is illuminated only if there is continuity through the breaker trip coil. There is no SCADA monitor or relay monitor of this trip coil. The line protection relay package that trips this circuit breaker is a microprocessor relay that has an integral alarm relay that will assert on a number of conditions that includes a loss of power to the relay. This alarm contact connects to our SCADA system and alerts our 24-hour operations center of relay trouble when the alarm contact closes. This microprocessor relay trips the circuit breaker only and does not monitor trip coil continuity or other things such as trip current. Are the components monitored or not? How often must I perform maintenance?

The protective relay is monitored and can be maintained every 12 years, or when an Unresolved Maintenance Issue arises. The control circuitry can be maintained every 12 years. The circuit breaker trip coil(s) has to be electrically operated at least once every six years.

What is a mitigating device?

A mitigating device is the device that acts to respond as directed by a Special Protection System. It may be a breaker, valve, distributed control system, or any variety of other devices. This response may include tripping, closing, or other control actions.

8. Maximum Allowable Verification Intervals

The maximum allowable testing intervals and maintenance activities show how CBM with newer device types can reduce the need for many of the tests and site visits that older Protection System components require. As explained below, there are some sections of the Protection System that monitoring or data analysis may not verify. Verifying these sections of the Protection System or Automatic Reclosing requires some persistent TBM activity in the maintenance program. However, some of this TBM can be carried out remotely - for example, exercising a circuit breaker through the relay tripping circuits using the relay remote control capabilities can be used to verify function of one tripping path and proper trip coil operation, if there has been no Fault or routine operation to demonstrate performance of relay tripping circuits.

8.1 Maintenance Tests

Periodic maintenance testing is performed to ensure that the protection and control system is operating correctly after a time period of field installation. These tests may be used to ensure that individual components are still operating within acceptable performance parameters - this type of test is needed for components susceptible to degraded or changing characteristics due to aging and wear. Full system performance tests may be used to confirm that the total Protection System functions from measurement of power system values, to properly identifying Fault characteristics, to the operation of the interrupting devices.

8.1.1 Table of Maximum Allowable Verification Intervals

Table 1 (collectively known as Table 1, individually called out as Tables 1-1 through 1-5), Table 2, Table 3, Table 4-1 through Table 4-2, and Table 5 in the standard specify maximum allowable verification intervals for various generations of Protection Systems, Automatic Reclosing and Sudden Pressure Relaying and categories of equipment that comprise these systems. The right column indicates maintenance activities required for each category.

The types of components are illustrated in Figures 1 and 2 at the end of this paper. Figure 1 shows an example of telecommunications-assisted transmission Protection System comprising substation equipment at each terminal and a telecommunications channel for relaying between the two substations. Figure 2 shows an example of a generation Protection System. The various sub-systems of a Protection System that need to be verified are shown.

Non-distributed UFLS, UVLS, and SPS are additional categories of Table 1 that are not illustrated in these figures. Non-distributed UFLS, UVLS and SPS all use identical equipment as Protection Systems in the performance of their functions; and, therefore, have the same maintenance needs.

Distributed UFLS and UVLS Systems, which use local sensing on the distribution System and trip co-located non-BES interrupting devices, are addressed in Table 3 with reduced maintenance activities.

While it is easy to associate protective relays to multiple levels of monitoring, it is also true that most of the components that can make up a Protection System can also have technological advancements that place them into higher levels of monitoring.

To use the Maintenance Activities and Intervals Tables from PRC-005-X:

- First find the Table associated with your component. The tables are arranged in the order of mention in the definition of Protection System;
    - Table 1-1 is for protective relays,
    - Table 1-2 is for the associated communications systems,
    - Table 1-3 is for current and voltage sensing devices,
    - Table 1-4 is for station dc supply and
    - Table 1-5 is for control circuits.
    - Table 2, is for alarms; this was broken out to simplify the other tables.
    - Table 3 is for components which make-up distributed UFLS and UVLS Systems.
    - Table 4 is for Automatic Reclosing.
    - Table 5 is for Sudden Pressure Relaying.
- Next look within that table for your device and its degree of monitoring. The Tables have different hands-on maintenance activities prescribed depending upon the degree to which you monitor your equipment. Find the maintenance activity that applies to the monitoring level that you have on your piece of equipment.
- This Maintenance activity is the minimum maintenance activity that must be documented.
- If your Performance-Based Maintenance (PBM) plan requires <u>more activities,</u> then you must perform and document to this higher standard. (Note that this does not apply unless you utilize PBM.)
- After the maintenance activity is known, check the maximum maintenance interval; this time is the maximum time allowed between hands-on maintenance activity cycles of this component.
- If your Performance-Based Maintenance plan requires activities <u>more often</u> than the Tables maximum, then you must perform and document those activities to your more stringent standard. (Note that this does not apply unless you utilize PBM.)
- Any given component of a Protection System can be determined to have a degree of monitoring that may be different from another component within that same Protection System. For example, in a given Protection System it is possible for an entity to have a monitored protective relay and an unmonitored associated communications system; this combination would require hands-on maintenance activity on the relay at least once every 12 years and attention paid to the communications system as often as every four months.
- An entity does not have to utilize the extended time intervals made available by this use of condition-based monitoring. An easy choice to make is to simply utilize the unmonitored level of maintenance made available in each of the Tables. While the maintenance activities resulting from this choice would require more maintenance man-hours, the maintenance requirements may be simpler to document and the resulting maintenance plans may be easier to create.

For each Protection System Component, Table 1 shows maximum allowable testing intervals for the various degrees of monitoring. For each Automatic Reclosing Component, Table 4 shows maximum allowable testing intervals for the various degrees of monitoring. These degrees of monitoring, or levels, range from the legacy unmonitored through a system that is more comprehensively monitored.

It has been noted here that an entity may have a PSMP that is more stringent than PRC-005-X. There may be any number of reasons that an entity chooses a more stringent plan than the minimums prescribed within PRC-005-X, most notable of which is an entity using performance based maintenance methodology. If an entity has a Performance-Based Maintenance program, then that plan must be followed, even if the plan proves to be more stringent than the minimums laid out in the Tables.

8.1.2 Additional Notes for Tables 1-1 through 1-5, Table 3, and Table 4

1. For electromechanical relays, adjustment is required to bring measurement accuracy within the tolerance needed by the asset owner. Microprocessor relays with no remote monitoring of alarm contacts, etc., are unmonitored relays and need to be verified within the Table interval as other unmonitored relays but may be verified as functional by means other than testing by simulated inputs.

2. Microprocessor relays typically are specified by manufacturers as not requiring calibration, but acceptable measurement of power system input values must be verified (verification of the Analog to Digital [A/D] converters) within the Table intervals. The integrity of the digital inputs and outputs that are used as protective functions must be verified within the Table intervals.

3. Any Phasor Measurement Unit (PMU) function whose output is used in a Protection System or SPS (as opposed to a monitoring task) must be verified as a component in a Protection System.

4. In addition to verifying the circuitry that supplies dc to the Protection System, the owner must maintain the station dc supply. The most widespread station dc supply is the station battery and charger. Unlike most Protection System components, physical inspection of station batteries for signs of component failure, reduced performance, and degradation are required to ensure that the station battery is reliable enough to deliver dc power when required. IEEE Standards 450, 1188, and 1106 for vented lead-acid, valve-regulated lead-acid, and nickel-cadmium batteries, respectively (which are the most commonly used substation batteries on the NERC BES) have been developed as an important reference source of maintenance recommendations. The Protection System owner might want to follow the guidelines in the applicable IEEE recommended practices for battery maintenance and testing, especially if the battery in question is used for application requirements in addition to the protection and control demands covered under this standard. However, the Standard Drafting Team has tailored the battery maintenance and testing guidelines in PRC-005-X for the Protection System owner which are application specific for the BES Facilities. While the IEEE recommendations are all encompassing, PRC-005-X is a more economical approach while addressing the reliability requirements of the BES.

5. Aggregated small entities might distribute the testing of the population of UFLS/UVLS systems, and large entities will usually maintain a portion of these systems in any given year. Additionally, if relatively small quantities of such systems do not perform properly, it will not affect the integrity of the overall program. Thus, these distributed systems have decreased requirements as compared to other Protection Systems.

6. Voltage & current sensing device circuit input connections to the Protection System relays can be verified by (but not limited to) comparison of measured values on live circuits or by using test currents and voltages on equipment out of service for maintenance. The verification process can be automated or manual. The values should be verified to be as expected (phase value and phase relationships are both equally important to verify).

7. "End-to-end test," as used in this Supplementary Reference, is any testing procedure that creates a remote input to the local communications-assisted trip scheme. While this can be interpreted as a GPS-type functional test, it is not limited to testing via GPS. Any remote scheme manipulation that can cause action at the local trip path can be used to functionally-test the dc control circuitry. A documented Real-time trip of any given trip path is acceptable in lieu of a functional trip test. It is possible, with sufficient monitoring, to be able to verify each and every parallel trip path that participated in any given dc control circuit trip. Or another possible solution is that a single trip path from a single monitored relay can be verified to be the trip path that successfully tripped during a Real-time operation. The variations are only limited by the degree of engineering and monitoring that an entity desires to pursue.

8. A/D verification may use relay front panel value displays, or values gathered via data communications. Groupings of other measurements (such as vector summation of bus feeder currents) can be used for comparison if calibration requirements assure acceptable measurement of power system input values.

9. Notes 1-8 attempt to describe some testing activities; they do not represent the only methods to achieve these activities, but rather some possible methods. Technological advances, ingenuity and/or industry accepted techniques can all be used to satisfy maintenance activity requirements; the standard is technology- and method-neutral in most cases.

8.1.3 Frequently Asked Questions:

What is meant by "Verify that settings are as specified" maintenance activity in Table 1-1?

Verification of settings is an activity directed mostly towards microprocessor- based relays. For relay maintenance departments that choose to test microprocessor-based relays in the same manner as electromechanical relays are tested, the testing process sometimes requires that some specific functions be disabled. Later tests might enable the functions previously disabled, but perhaps still other functions or logic statements were then masked out. It is imperative that, when the relay is placed into service, the settings in the relay be the settings that were intended to be in that relay or as the standard states "…settings are as specified."

Many of the microprocessor- based relays available today have software tools which provide this functionality and generate reports for this purpose.

For evidence or documentation of this requirement, a simple recorded acknowledgement that the settings were checked to be as specified is sufficient.

The drafting team was careful not to require "…that the relay settings be correct…" because it was believed that this might then place a burden of proof that the specified settings would result in the correct intended operation of the interrupting device. While that is a noble intention, the measurable proof of such a requirement is immense. The intent is that settings of the component be as specified at the conclusion of maintenance activities, whether those settings may have "drifted" since the prior maintenance or whether changes were made as part of the testing process.

Are electromechanical relays included in the "Verify that settings are as specified" maintenance activity in Table 1-1?

Verification of settings is an activity directed towards the application of protection related functions of microprocessor based relays. Electromechanical relays require calibration verification by voltage and/or current injection; and, thus, the settings are verified during calibration activity. In the example of a time-overcurrent relay, a minor deviation in time dial, versus the settings, may be acceptable, as long as the relay calibration is within accepted tolerances at the injected current amplitudes. A major deviation may require further investigation, as it could indicate a problem with the relay or an incorrect relay style for the application.

The verification of phase current and voltage measurements by comparison to other quantities seems reasonable. How, though, can I verify residual or neutral currents, or 3V0 voltages, by comparison, when my system is closely balanced?

Since these inputs are verified at commissioning, maintenance verification requires ensuring that phase quantities are as expected and that 3IO and 3VO quantities appear equal to or close to 0.

These quantities also may be verified by use of oscillographic records for connected microprocessor relays as recorded during system Disturbances. Such records may compare to similar values recorded at other locations by other microprocessor relays for the same event, or compared to expected values (from short circuit studies) for known Fault locations.

What does this Standard require for testing an auxiliary tripping relay?

Table 1 and Table 3 requires that a trip test must verify that the auxiliary tripping relay(s) and/or lockout relay(s) which are directly in a trip path from the protective relay to the interrupting device trip coil operate(s) electrically. Auxiliary outputs not in a trip path (i.e. annunciation or DME input) are not required, by this standard, to be checked.

Do I have to perform a full end-to-end test of a Special Protection System?

No. All portions of the SPS need to be maintained, and the portions must overlap, but the overall SPS does not need to have a single end-to-end test. In other words it may be tested in piecemeal fashion provided all of the pieces are verified.

What about SPS interfaces between different entities or owners?

As in all of the Protection System requirements, SPS segments can be tested individually, thus minimizing the need to accommodate complex maintenance schedules.

What do I have to do if I am using a phasor measurement unit (PMU) as part of a Protection System or Special Protection System?

Any Phasor Measurement Unit (PMU) function whose output is used in a Protection System or Special Protection System (as opposed to a monitoring task) must be verified as a component in a Protection System.

How do I maintain a Special Protection System or relay sensing for non-distributed UFLS or UVLS Systems?

Since components of the SPS, UFLS and UVLS are the same types of components as those in Protection Systems, then these components should be maintained like similar components used for other Protection System functions. In many cases the devices for SPS, UFLS and UVLS are also used for other protective functions. The same maintenance activities apply with the exception that distributed systems (UFLS and UVLS) have fewer dc supply and control circuitry maintenance activity requirements.

For the testing of the output action, verification may be by breaker tripping, but may be verified in overlapping segments. For example, an SPS that trips a remote circuit breaker might be tested by testing the various parts of the scheme in overlapping segments. Another method is to document the Real-time tripping of an SPS scheme should that occur. Forced trip tests of circuit breakers (etc.) that are a part of distributed UFLS or UVLS schemes are not required.

The established maximum allowable intervals do not align well with the scheduled outages for my power plant. Can I extend the maintenance to the next scheduled outage following the established maximum interval?

No. You must complete your maintenance within the established maximum allowable intervals in order to be compliant. You will need to schedule your maintenance during available outages to complete your maintenance as required, even if it means that you may do protective relay maintenance more frequently than the maximum allowable intervals. The maintenance intervals were selected with typical plant outages, among other things, in mind.

If I am unable to complete the maintenance, as required, due to a major natural disaster (hurricane, earthquake, etc.), how will this affect my compliance with this standard?

The Sanction Guidelines of the North American Electric Reliability Corporation, effective January 15, 2008, provides that the Compliance Monitor will consider extenuating circumstances when considering any sanctions.

What if my observed testing results show a high incidence of out-of-tolerance relays; or, even worse, I am experiencing numerous relay Misoperations due to the relays being out-of-tolerance?

The established maximum time intervals are mandatory only as a not-to-exceed limitation. The establishment of a maximum is measurable. But any entity can choose to test some or all of their Protection System components more frequently (or to express it differently, exceed the minimum requirements of the standard). Particularly if you find that the maximum intervals in the standard do not achieve your expected level of performance, it is understandable that you

would maintain the related equipment more frequently. A high incidence of relay Misoperations is in no one's best interest.

We believe that the four-month interval between inspections is unneccessary. Why can we not perform these inspections twice per year?

The Standard Drafting Team, through the comment process, has discovered that routine monthly inspections are not the norm. To align routine station inspections with other important inspections, the four-month interval was chosen. In lieu of station visits, many activities can be accomplished with automated monitoring and alarming.

Our maintenance plan calls for us to perform routine protective relay tests every 3 years. If we are unable to achieve this schedule, but we are able to complete the procedures in less than the maximum time interval ,then are we in or out of compliance?

According to R3, if you have a time-based maintenance program, then you will be in violation of the standard only if you exceed the maximum maintenance intervals prescribed in the Tables. According to R4, if your device in question is part of a Performance-Based Maintenance program, then you will be in violation of the standard if you fail to meet your PSMP, even if you do not exceed the maximum maintenance intervals prescribed in the Tables. The intervals in the Tables are associated with TBM and CBM; Attachment A is associated with PBM.

Please provide a sample list of devices or systems that must be verified in a generator, generator step-up transformer, generator connected station service or generator connected excitation transformer to meet the requirements of this maintenance standard.

Examples of typical devices and systems that may directly trip the generator, or trip through a lockout relay, may include, but are not necessarily limited to:

- Fault protective functions, including distance functions, voltage-restrained overcurrent functions, or voltage-controlled overcurrent functions
- Loss-of-field relays
- Volts-per-hertz relays
- Negative sequence overcurrent relays
- Over voltage and under voltage protection relays
- Stator-ground relays
- Communications-based Protection Systems such as transfer-trip systems
- Generator differential relays
- Reverse power relays
- Frequency relays
- Out-of-step relays
- Inadvertent energization protection

- Breaker failure protection

For generator step-up, generator-connected station service transformers, or generator connected excitation transformers, operation of any of the following associated protective relays frequently would result in a trip of the generating unit; and, as such, would be included in the program:

- Transformer differential relays
- Neutral overcurrent relay
- Phase overcurrent relays

Relays which trip breakers serving station auxiliary Loads such as pumps, fans, or fuel handling equipment, etc., need not be included in the program, even if the loss of the those Loads could result in a trip of the generating unit. Furthermore, relays which provide protection to secondary unit substation (SUS) or low switchgear transformers and relays protecting other downstream plant electrical distribution system components are not included in the scope of this program, even if a trip of these devices might eventually result in a trip of the generating unit. For example, a thermal overcurrent trip on the motor of a coal-conveyor belt could eventually lead to the tripping of the generator, but it does not cause the trip.

In the case where a plant does not have a generator connected station service transformer such that it is normally fed from a system connected station service transformer, is it still the drafting team's intent to exclude the Protection Systems for these system connected auxiliary transformers from scope even when the loss of the normal (system connected) station service transformer will result in a trip of a BES generating Facility?

The SDT does not intend that the system-connected station service transformers be included in the Applicability. The generator-connected station service transformers and generator connected excitation transformers are often connected to the generator bus directly without an interposing breaker; thus, the Protection Systems on these transformers will trip the generator as discussed in 4.2.5.1.

What is meant by "verify operation of the relay inputs and outputs that are essential to proper functioning of the Protection System?"

Any input or output (of the relay) that "affects the tripping" of the breaker is included in the scope of I/O of the relay to be verified. By "affects the tripping," one needs to realize that sometimes there are more inputs and outputs than simply the output to the trip coil. Many important protective functions include things like breaker fail initiation, zone timer initiation and sometimes even 52a/b contact inputs are needed for a protective relay to correctly operate.

Each input should be "picked up" or "turned on and off" and verified as changing state by the microprocessor of the relay. Each output should be "operated" or "closed and opened" from the microprocessor of the relay and the output should be verified to change state on the output terminals of the relay. One possible method of testing inputs of these relays is to "jumper" the needed dc voltage to the input and verify that the relay registered the change of state.

Electromechanical lock-out relays (86) (used to convey the tripping current to the trip coils) need to be electrically operated to prove the capability of the device to change state. These tests need to be accomplished at least every six years, unless PBM methodology is applied.

The contacts on the 86 or auxiliary tripping relays (94) that change state to pass on the trip current to a breaker trip coil need only be checked every 12 years with the control circuitry.

What is the difference between a distributed UFLS/UVLS and a non-distributed UFLS/UVLS scheme?

A distributed UFLS or UVLS scheme contains individual relays which make independent Load shed decisions based on applied settings and localized voltage and/or current inputs. A distributed scheme may involve an enable/disable contact in the scheme and still be considered a distributed scheme. A non-distributed UFLS or UVLS scheme involves a system where there is some type of centralized measurement and Load shed decision being made. A non-distributed UFLS/UVLS scheme is considered similar to an SPS scheme and falls under Table 1 for maintenance activities and intervals.

8.2 Retention of Records

PRC-005-1 describes a reporting or auditing cycle of one year and retention of records for three years. However, with a three-year retention cycle, the records of verification for a Protection System might be discarded before the next verification, leaving no record of what was done if a Misoperation or failure is to be analyzed.

PRC-005-X corrects this by requiring:

The Transmission Owner, Generator Owner, and Distribution Provider shall each retain documentation of the most recent performance of each distinct maintenance activity for the Protection System, Automatic Reclosing, or Sudden Pressure Relaying Component, or to the previous scheduled (on-site) audit date, whichever is longer.

This requirement assures that the documentation shows that the interval between maintenance cycles correctly meets the maintenance interval limits. The requirement is actually alerting the industry to documentation requirements already implemented by audit teams. Evidence of compliance bookending the interval shows interval accomplished instead of proving only your planned interval.

The SDT is aware that, in some cases, the retention period could be relatively long. But, the retention of documents simply helps to demonstrate compliance.

8.2.1 Frequently Asked Questions:

Please clarify the data retention requirements.

The data retention requirements are intended to allow the availability of maintenance records to demonstrate that the time intervals in your maintenance plan were upheld.

Maximum Maintenance Interval	**Data Retention Period**
4 Months, 6 Months,18 Months, or 3 Years	All activities since previous audit

6 Years	All activities since previous audit(assuming a 6 year audit cycle) or most recent performance(assuming 3 year audit cycle), whichever is longer
12 Year	All activities from the most recent performance

If an entity prefers to utilize Performance-Based Maintenance, then statistical data may well be retained for extended periods to assist with future adjustments in time intervals.

If an equipment item is replaced, then the entity can restart the maintenance-time-interval-clock if desired; however, the replacement of equipment does not remove any documentation requirements that would have been required to verify compliance with time-interval requirements. In other words, do not discard maintenance data that goes to verify your work.

The retention of documentation for new and/or replaced equipment is all about proving that the maintenance intervals had been in compliance. For example, a long-range plan of upgrades might lead an entity to ignore required maintenance; retaining the evidence of prior maintenance that existed before any retirements and upgrades proves compliance with the standard.

What does this Maintenance Standard say about commissioning? Is it necessary to have documentation in your maintenance history of the completion of commission testing?

This standard does not establish requirements for commission testing. Commission testing includes all testing activities necessary to conclude that a Facility has been built in accordance with design. While a thorough commission testing program would include, either directly or indirectly, the verification of all those Protection System attributes addressed by the maintenance activities specified in the Tables of PRC-005-X, verification of the adequacy of initial installation necessitates the performance of testing and inspections that go well beyond these routine maintenance activities. For example, commission testing might set baselines for future tests; perform acceptance tests and/or warranty tests; utilize testing methods that are not generally done routinely like staged-Fault-tests.

However, many of the Protection System attributes which are verified during commission testing are not subject to age related or service related degradation, and need not be re-verified within an ongoing maintenance program. Example – it is not necessary to re-verify correct terminal strip wiring on an ongoing basis.

PRC-005-X assumes that thorough commission testing was performed prior to a Protection System being placed in service. PRC-005-X 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.

It should be noted that commission testing frequently is performed by a different organization than that which is responsible for the ongoing maintenance of the Protection System. Furthermore, the commission testing activities will not necessarily correlate directly with the maintenance activities required by the standard. As such, it is very likely that commission testing records will deviate significantly from maintenance records in both form and content; and,

therefore, it is not necessary to maintain commission testing records within the maintenance program documentation.

Notwithstanding the differences in records, an entity would be wise to retain commissioning records to show a maintenance start date. (See below). An entity that requires that their commissioning tests have, at a minimum, the requirements of PRC-005-X would help that entity prove time interval maximums by setting the initial time clock.

How do you determine the initial due date for maintenance?

The initial due date for maintenance should be based upon when a Protection System was tested. Alternatively, an entity may choose to use the date of completion of the commission testing of the Protection System component and the system was placed into service as the starting point in determining its first maintenance due dates. Whichever method is chosen, for newly installed Protection Systems the components should not be placed into service until minimum maintenance activities have taken place.

It is conceivable that there can be a (substantial) difference in time between the date of testing, as compared to the date placed into service. The use of the "Calendar Year" language can help determine the next due date without too much concern about being non-compliant for missing test dates by a small amount (provided your dates are not already at the end of a year). However, if there is a substantial amount of time difference between testing and in-service dates, then the testing date should be followed because it is the degradation of components that is the concern. While accuracy fluctuations may decrease when components are not energized, there are cases when degradation can take place, even though the device is not energized. Minimizing the time between commissioning tests and in-service dates will help.

If I miss two battery inspections four times out of 100 Protection System components on my transmission system, does that count as 2% or 8% when counting Violation Severity Level (VSL) for R3?

The entity failed to complete its scheduled program on two of its 100 Protection System components, which would equate to 2% for application to the VSL Table for Requirement R3. This VSL is written to compare missed components to total components. In this case two components out of 100 were missed, or 2%.

How do I achieve a "grace period" without being out of compliance?

The objective here is to create a time extension within your own PSMP that still does not violate the maximum time intervals stated in the standard. Remember that the maximum time intervals listed in the Tables cannot be extended.

For the purposes of this example, concentrating on just unmonitored protective relays – Table 1-1 specifies a maximum time interval (between the mandated maintenance activities) of six calendar years. Your plan must ensure that your unmonitored relays are tested at least once every six calendar years. You could, within your PSMP, require that your unmonitored relays be tested every four calendar years, with a maximum allowable time extension of 18 calendar months. This allows an entity to have deadlines set for the auto-generation of work orders, but still has the flexibility in scheduling complex work schedules. This also allows for that 18 calendar months to act as a buffer, in effect a grace period within your PSMP, in the event of unforeseen events. You will note that this example of a maintenance plan interval has a planned time of four years; it also has a built-in time extension allowed within the PSMP, and yet does not exceed the maximum time interval allowed by the standard. So while there are no time extensions allowed beyond the standard, an entity can still have substantial flexibility to maintain their Protection System components.

8.3 Basis for Table 1 Intervals

When developing the original *Protection System Maintenance – A Technical Reference* in 2007, the SPCTF collected all available data from Regional Entities (REs) on time intervals recommended for maintenance and test programs. The recommendations vary widely in categorization of relays, defined maintenance actions, and time intervals, precluding development of intervals by averaging. The SPCTF also reviewed the 2005 Report [2] of the IEEE Power System Relaying Committee Working Group I-17 (Transmission Relay System Performance Comparison). Review of the I-17 report shows data from a small number of utilities, with no company identification or means of investigating the significance of particular results.

To develop a solid current base of practice, the SPCTF surveyed its members regarding their maintenance intervals for electromechanical and microprocessor relays, and asked the members to also provide definitively-known data for other entities. The survey represented 470 GW of peak Load, or 4% of the NERC peak Load. Maintenance interval averages were compiled by weighting reported intervals according to the size (based on peak Load) of the reporting utility. Thus, the averages more accurately represent practices for the large populations of Protection Systems used across the NERC regions.

The results of this survey with weighted averaging indicate maintenance intervals of five years for electromechanical or solid state relays, and seven years for unmonitored microprocessor relays.

A number of utilities have extended maintenance intervals for microprocessor relays beyond seven years, based on favorable experience with the particular products they have installed. To provide a technical basis for such extension, the SPCTF authors developed a recommendation of 10 years using the Markov modeling approach from [1], as summarized in Section 8.4. The results of this modeling depend on the completeness of self-testing or monitoring. Accordingly, this extended interval is allowed by Table 1, only when such relays are monitored as specified in the attributes of monitoring contained in Tables 1-1 through 1-5 and Table 2. Monitoring is capable of reporting Protection System health issues that are likely to affect performance within the 10 year time interval between verifications.

It is important to note that, according to modeling results, Protection System availability barely changes as the maintenance interval is varied below the 10-year mark. Thus, reducing the maintenance interval does not improve Protection System availability. With the assumptions of the model regarding how maintenance is carried out, reducing the maintenance interval actually degrades Protection System availability.

8.4 Basis for Extended Maintenance Intervals for Microprocessor Relays

Table 1 allows maximum verification intervals that are extended based on monitoring level. The industry has experience with self-monitoring microprocessor relays that leads to the Table 1 value for a monitored relay, as explained in Section 8.3. To develop a basis for the maximum interval for monitored relays in their *Protection System Maintenance – A Technical Reference*, the SPCTF used the methodology of Reference [1], which specifically addresses optimum routine maintenance intervals. The Markov modeling approach of [1] is judged to be valid for the design and typical failure modes of microprocessor relays.

The SPCTF authors ran test cases of the Markov model to calculate two key probability measures:

- Relay Unavailability - the probability that the relay is out of service due to failure or maintenance activity while the power system Element to be protected is in service.
- Abnormal Unavailability - the probability that the relay is out of service due to failure or maintenance activity when a Fault occurs, leading to failure to operate for the Fault.

The parameter in the Markov model that defines self-monitoring capability is ST (for self-test). ST = 0 if there is no self-monitoring; ST = 1 for full monitoring. Practical ST values are estimated to range from .75 to .95. The SPCTF simulation runs used constants in the Markov model that were the same as those used in [1] with the following exceptions:

Sn, Normal tripping operations per hour = 21600 (reciprocal of normal Fault clearing time of 10 cycles)

Sb, Backup tripping operations per hour = 4320 (reciprocal of backup Fault clearing time of 50 cycles)

Rc, Protected component repairs per hour = 0.125 (8 hours to restore the power system)

Rt, Relay routine tests per hour = 0.125 (8 hours to test a Protection System)

Rr, Relay repairs per hour = 0.08333 (12 hours to complete a Protection System repair after failure)

Experimental runs of the model showed low sensitivity of optimum maintenance interval to these parameter adjustments.

The resulting curves for relay unavailability and abnormal unavailability versus maintenance interval showed a broad minimum (optimum maintenance interval) in the vicinity of 10 years – the curve is flat, with no significant change in either unavailability value over the range of 9, 10, or 11 years. This was true even for a relay mean time between Failures (MTBF) of 50 years, much lower than MTBF values typically published for these relays. Also, the Markov modeling indicates that both the relay unavailability and abnormal unavailability actually become higher with more frequent testing. This shows that the time spent on these more frequent tests yields no failure discoveries that approach the negative impact of removing the relays from service and running the tests.

The PSMT SDT discussed the practical need for "time-interval extensions" or "grace periods" to allow for scheduling problems that resulted from any number of business contingencies. The time interval discussions also focused on the need to reflect industry norms surrounding Generator outage frequencies. Finally, it was again noted that FERC Order 693 demanded maximum time intervals. "Maximum time intervals" by their very term negates any "time-interval extension" or "grace periods." To recognize the need to follow industry norms on Generator outage frequencies and accommodate a form of time-interval extension, while still following FERC Order 693, the Standard Drafting Team arrived at a six-year interval for the electromechanical relay, instead of the five-year interval arrived at by the SPCTF. The PSMT SDT has followed the FERC directive for a *maximum* time interval and has determined that no extensions will be allowed. Six years has been set for the maximum time interval between manual maintenance activities. This maximum time interval also works well for maintenance cycles that have been in use in generator plants for decades.

For monitored relays, the PSMT SDT notes that the SPCTF called for 10 years as the interval between maintenance activities. This 10-year interval was chosen, even though there was "…no significant change in unavailability value over the range of 9, 10, or 11 years. This was true even for a relay Mean Time between Failures (MTBF) of 50 years…" The Standard Drafting Team again sought to align maintenance activities with known successful practices and outage schedules. The Standard does not allow extensions on any component of the Protection System; thus, the maximum allowed interval for these components has been set to 12 years. Twelve years also fits well into the traditional maintenance cycles of both substations and generator plants.

Also of note is the Table's use of the term "Calendar" in the column for "Maximum Maintenance Interval." The PSMT SDT deemed it necessary to include the term "Calendar" to facilitate annual maintenance planning, scheduling and implementation. This need is the result of known occurrences of system requirements that could cause maintenance schedules to be missed by a few days or weeks. The PSMT SDT chose the term "Calendar" to preclude the need to have schedules be met to the day. An electromechanical protective relay that is maintained in year number one need not be revisited until six years later (year number seven). For example, a relay was maintained April 10, 2008; maintenance would need to be completed no later than December 31, 2014.

Though not a requirement of this standard, to stay in line with many Compliance Enforcement Agencies audit processes an entity should define, within their own PSMP, the entity's use of terms like annual, calendar year, etc. Then, once this is within the PSMP, the entity should abide by their chosen language.

9. Performance-Based Maintenance Process

In lieu of using the Table 1 intervals, a Performance-Based Maintenance process may be used to establish maintenance intervals (*PRC-005 Attachment A Criteria for a Performance-Based Protection System Maintenance Program*). A Performance-Based Maintenance process may justify longer maintenance intervals, or require shorter intervals relative to Table 1. In order to use a Performance-Based Maintenance process, the documented maintenance program must include records of repairs, adjustments, and corrections to covered Protection Systems in order to provide historical justification for intervals, other than those established in Table 1. Furthermore, the asset owner must regularly analyze these records of corrective actions to develop a ranking of causes. Recurrent problems are to be highlighted, and remedial action plans are to be documented to mitigate or eliminate recurrent problems.

Entities with Performance-Based Maintenance track performance of Protection Systems, demonstrate how they analyze findings of performance failures and aberrations, and implement continuous improvement actions. Since no maintenance program can ever guarantee that no malfunction can possibly occur, documentation of a Performance-Based Maintenance program would serve the utility well in explaining to regulators and the public a Misoperation leading to a major System outage event.

A Performance-Based Maintenance program requires auditing processes like those included in widely used industrial quality systems (such as ***ISO 9001-2000, Quality Management Systems — Requirements;*** or applicable parts of the NIST Baldridge National Quality Program). The audits periodically evaluate:

- The completeness of the documented maintenance process
- Organizational knowledge of and adherence to the process
- Performance metrics and documentation of results
- Remediation of issues
- Demonstration of continuous improvement.

In order to opt into a Performance-Based Maintenance (PBM) program, the asset owner must first sort the various Components into population segments. Any population segment must be comprised of at least 60 individual units; if any asset owner opts for PBM, but does not own 60 units to comprise a population, then that asset owner may combine data from other asset owners until the needed 60 units is aggregated. Each population segment must be composed of a grouping of Components of a consistent design standard or particular model or type from a single manufacturer and subjected to similar environmental factors. For example: One segment cannot be comprised of both GE & Westinghouse electro-mechanical lock-out relays; likewise, one segment cannot be comprised of 60 GE lock-out relays, 30 of which are in a dirty environment, and the remaining 30 from a clean environment. This PBM process cannot be applied to batteries, but can be applied to all other Components, including (but not limited to) specific battery chargers, instrument transformers, trip coils and/or control circuitry (etc.).

9.1 Minimum Sample Size

Large Sample Size

An assumption that needs to be made when choosing a sample size is "the sampling distribution of the sample mean can be approximated by a normal probability distribution." The Central Limit Theorem states: "In selecting simple random samples of size *n* from a population, the sampling distribution of the sample mean *x* can be approximated by a normal probability distribution as the sample size becomes large." (Essentials of Statistics for Business and Economics, Anderson, Sweeney, Williams, 2003.)

To use the Central Limit Theorem in statistics, the population size should be large. The references below are supplied to help define what is large.

> "… whenever we are using a large simple random sample (rule of thumb: n>=30), the central limit theorem enables us to conclude that the sampling distribution of the sample mean can be approximated by a normal distribution." (Essentials of Statistics for Business and Economics, Anderson, Sweeney, Williams, 2003.)
>
> "If samples of size n, when n>=30, are drawn from any population with a mean *u* and a standard deviation σ, the sampling distribution of sample means approximates a normal distribution. The greater the sample size, the better the approximation." (Elementary Statistics - Picturing the World, Larson, Farber, 2003.)
>
> "The sample size is large (generally n>=30)… (Introduction to Statistics and Data Analysis - Second Edition, Peck, Olson, Devore, 2005.)
>
> "… the normal is often used as an approximation to the *t* distribution in a test of a null hypothesis about the mean of a normally distributed population when the population variance is estimated from a relatively large sample. A sample size exceeding 30 is often given as a minimal size in this connection." (Statistical Analysis for Business Decisions, Peters, Summers, 1968.)

Error of Distribution Formula

Beyond the large sample size discussion above, a sample size requirement can be estimated using the bound on the Error of Distribution Formula when the expected result is of a "Pass/Fail" format and will be between 0 and 1.0.

The Error of Distribution Formula is:

$$B = z\sqrt{\frac{\pi(1-\pi)}{n}}$$

Where:

B = bound on the error of distribution (allowable error)

z = standard error

π = expected failure rate

n = sample size required

Solving for n provides:

$$n = \pi(1-\pi)\left(\frac{z}{B}\right)^2$$

Minimum Population Size to use Performance-Based Program

One entity's population of components should be large enough to represent a sizeable sample of a vendor's overall population of manufactured devices. For this reason, the following assumptions are made:

B = 5%

z = 1.96 (This equates to a 95% confidence level)

π = 4%

Using the equation above, n=59.0.

Minimum Sample Size to evaluate Performance-Based Program

The number of components that should be included in a sample size for evaluation of the appropriate testing interval can be smaller because a lower confidence level is acceptable since the sample testing is repeated or updated annually. For this reason, the following assumptions are made:

B = 5%

z = 1.44 (85% confidence level)

π = 4%

Using the equation above, n=31.8.

Recommendation

Based on the above discussion, a sample size should be at least 30 to allow use of the equation mentioned. Using this and the results of the equation, the following numbers are recommended (and required within the standard):

Minimum Population Size to use Performance-Based Maintenance Program = 60

Minimum Sample Size to evaluate Performance-Based Program = 30.

Once the population segment is defined, then maintenance must begin within the intervals as outlined for the device described in the Tables 1-1 through 1-5. Time intervals can be lengthened provided the last year's worth of components tested (or the last 30 units maintained, whichever is more) had fewer than 4% Countable Events. It is notable that 4% is specifically chosen because an entity with a small population (30 units) would have to adjust its time intervals between maintenance if more than one Countable Event was found to have occurred during the last analysis period. A smaller percentage would require that entity to adjust the time interval between maintenance activities if even one unit is found out of tolerance or causes a Misoperation.

The minimum number of units that can be tested in any given year is 5% of the population. Note that this 5% threshold sets a practical limitation on total length of time between intervals at 20 years.

If at any time the number of Countable Events equals or exceeds 4% of the last year's tested components (or the last 30 units maintained, whichever is more), then the time period between manual maintenance activities must be decreased. There is a time limit on reaching the decreased time at which the Countable Events is less than 4%; this must be attained within three years.

Performance-Based Program Evaluation Example

The 4% performance target was derived as a protection system performance target and was selected based on the drafting team's experience and studies performed by several utilities. This is not derived from the performance of discrete devices. Microprocessor relays and electromechanical relays have different performance levels. It is not appropriate to compare these performance levels to each other. The performance of the segment should be compared to the 4% performance criteria.

In consideration of the use of Performance Based Maintenance (PBM), the user should consider the effects of extended testing intervals and the established 4% failure rate. In the table shown below, the segment is 1000 units. As the testing interval (in years) increases, the number of units tested each year decreases. The number of countable events allowed is 4% of the tested units. Countable events are the failure of a Component requiring repair or replacement, any corrective actions performed during the maintenance test on the units within the testing segment (units per year), or any misoperation attributable to hardware failure or calibration failure found within the entire segment (1000 units) during the testing year.

Example: 1000 units in the segment with a testing interval of 8 years: The number of units tested each year will be 125 units. The total allowable countable events equals: 125 X .04 = 5. This number includes failure of a Component requiring repair or replacement, corrective issues found during testing, and the total number of misoperations (attributable to hardware or calibration failure within the testing year) associated with the entire segment of 1000 units.

Example: 1000 units in the segment with a testing interval of 16 years: The number of units tested each year will be 63 units. The total allowable countable events equals: 63 X .04 = 2.5.

As shown in the above examples, doubling the testing interval reduces the number of allowable events by half.

Total number of units in the segment	1000
Failure rate	4.00%

Testing Intervals (Years)	Units Per Year	Acceptable Number of Countable Events per year	Yearly Failure Rate Based on 1000 Units in Segment
1	1000.00	40.00	4.00%
2	500.00	20.00	2.00%
4	250.00	10.00	1.00%
6	166.67	6.67	0.67%
8	125.00	5.00	0.50%
10	100.00	4.00	0.40%
12	83.33	3.33	0.33%
14	71.43	2.86	0.29%
16	62.50	2.50	0.25%
18	55.56	2.22	0.22%
20	50.00	2.00	0.20%

Using the prior year's data, determine the maximum allowable maintenance interval for each Segment such that the Segment experiences Countable Events on no more than 4% of the Components within the Segment, for the greater of either the last 30 Components maintained or all Components maintained in the previous year.

Segment – Components of a consistent design standard, or a particular model or type from a single manufacturer that typically share other common elements. Consistent performance is expected across the entire population of a Segment. A Segment must contain at least sixty (60) individual Components.

Countable Event – A failure of a Component requiring repair or replacement, any condition discovered during the maintenance activities in Tables 1-1 through 1-5, Table 3, Table 4-1 through Table 4-2, and Table 5, which requires corrective action or a Protection System Misoperation attributed to hardware failure or calibration failure. Misoperations due to product design errors, software errors, relay settings different from specified settings, Protection System Component, Automatic Reclosing, or Sudden Pressure Relaying configuration or application errors are not included in Countable Events.

9.2 Frequently Asked Questions:

I'm a small entity and cannot aggregate a population of Protection System components to establish a segment required for a Performance-Based Protection System Maintenance Program. How can I utilize that opportunity?

Multiple asset owning entities may aggregate their individually owned populations of individual Protection System components to create a segment that crosses ownership boundaries. All entities participating in a joint program should have a single documented joint management

process, with consistent Protection System Maintenance Programs (practices, maintenance intervals and criteria), for which the multiple owners are individually responsible with respect to the requirements of the Standard. The requirements established for Performance-Based Maintenance must be met for the overall aggregated program on an ongoing basis.

The aggregated population should reflect all factors that affect consistent performance across the population, including any relevant environmental factors such as geography, power-plant vs. substation, and weather conditions.

Can an owner go straight to a Performance-Based Maintenance program schedule, if they have previously gathered records?

Yes. An owner can go to a Performance-Based Maintenance program immediately. The owner will need to comply with the requirements of a Performance-Based Maintenance program as listed in the Standard. Gaps in the data collected will not be allowed; therefore, if an owner finds that a gap exists such that they cannot prove that they have collected the data as required for a Performance-Based Maintenance program then they will need to wait until they can prove compliance.

When establishing a Performance-Based Maintenance program, can I use test data from the device manufacturer, or industry survey results, as results to help establish a basis for my Performance-Based intervals?

No, you must use actual in-service test data for the components in the segment.

What types of Misoperations or events are not considered Countable Events in the Performance-Based Protection System Maintenance (PBM) Program?

Countable Events are intended to address conditions that are attributed to hardware failure or calibration failure; that is, conditions that reflect deteriorating performance of the component. These conditions include any condition where the device previously worked properly, then, due to changes within the device, malfunctioned or degraded to the point that re-calibration (to within the entity's tolerance) was required.

For this purpose of tracking hardware issues, human errors resulting in Protection System Misoperations during system installation or maintenance activities are not considered Countable Events. Examples of excluded human errors include relay setting errors, design errors, wiring errors, inadvertent tripping of devices during testing or installation, and misapplication of Protection System components. Examples of misapplication of Protection System components include wrong CT or PT tap position, protective relay function misapplication, and components not specified correctly for their installation. Obviously, if one is setting up relevant data about hardware failures then human failures should be eliminated from the hardware performance analysis.

One example of human-error is not pertinent data might be in the area of testing "86" lock-out relays (LOR). "Entity A" has two types of LOR's type "X" and type "Y"; they want to move into a performance based maintenance interval. They have 1000 of each type, so the population variables are met. During electrical trip testing of all of their various schemes over the initial six-year interval they find zero type "X" failures, but human error led to tripping a BES Element 100 times; they find 100 type "Y" failures and had an additional 100 human-error caused tripping incidents. In this example the human-error caused Misoperations should not be used to judge the performance of either type of LOR. Analysis of the data might lead "Entity A" to change time intervals. Type "X" LOR can be placed into extended time interval testing because of its low failure

rate (zero failures) while Type "Y" would have to be tested more often than every 6 calendar years (100 failures divided by 1000 units exceeds the 4% tolerance level).

Certain types of Protection System component errors that cause Misoperations are not considered Countable Events. Examples of excluded component errors include device malfunctions that are correctable by firmware upgrades and design errors that do not impact protection function.

What are some examples of methods of correcting segment perfomance for Performance-Based Maintenance?

There are a number of methods that may be useful for correcting segment performance for mal-performing segments in a Performance-Based Maintenance system. Some examples are listed below.

- The maximum allowable interval, as established by the Performance-Based Maintenance system, can be decreased. This may, however, be slow to correct the performance of the segment.
- Identifiable sub-groups of components within the established segment, which have been identified to be the mal-performing portion of the segment, can be broken out as an independent segment for target action. Each resulting segment must satisfy the minimum population requirements for a Performance-Based Maintenance program in order to remain within the program.
- Targeted corrective actions can be taken to correct frequently occurring problems. An example would be replacement of capacitors within electromechanical distance relays if bad capacitors were determined to be the cause of the mal-performance.
- components within the mal-performing segment can be replaced with other components (electromechanical distance relays with microprocessor relays, for example) to remove the mal-performing segment.

If I find (and correct) a Unresolved Maintenance Issue as a result of a Misoperation investigation (Re: PRC-004), how does this affect my Performance-Based Maintenance program?

If you perform maintenance on a Protection System component for any reason (including as part of a PRC-004 required Misoperation investigation/corrective action), the actions performed can count as a maintenance activity provided the activities in the relevant Tables have been done, and, if you desire, "reset the clock" on everything you've done. In a Performance-Based Maintenance program, you also need to record the Unresolved Maintenance Issue as a Countable Event within the relevant component group segment and use it in the analysis to determine your correct Performance-Based Maintenance interval for that component group. Note that "resetting the clock" should not be construed as interfering with an entity's routine testing schedule because the "clock-reset" would actually make for a decreased time interval by the time the next routine test schedule comes around.

For example a relay scheme, consisting of four relays, is tested on 1-1-11 and the PSMP has a time interval of 3 calendar years with an allowable extension of 1 calendar year. The relay would be due again for routine testing before the end of the year 2015. This mythical relay scheme has a Misoperation on 6-1-12 that points to one of the four relays as bad. Investigation proves a bad

relay and a new one is tested and installed in place of the original. This replacement relay actually could be retested before the end of the year 2016 (clock-reset) and not be out of compliance. This requires tracking maintenance by individual relays and is allowed. However, many companies schedule maintenance in other ways like by substation or by circuit breaker or by relay scheme. By these methods of tracking maintenance that “replaced relay” will be retested before the end of the year 2015. This is also acceptable. In no case was a particular relay tested beyond the PSMP of four years max, nor was the 6 year max of the Standard exceeded. The entity can reset the clock if they desire or the entity can continue with original schedules and, in effect, test even more frequently.

Why are batteries excluded from PBM? What about exclusion of batteries from condition based maintenance?

Batteries are the only element of a Protection System that is a perishable item with a shelf life. As a perishable item batteries require not only a constant float charge to maintain their freshness (charge), but periodic inspection to determine if there are problems associated with their aging process and testing to see if they are maintaining a charge or can still deliver their rated output as required.

Besides being perishable, a second unique feature of a battery that is unlike any other Protection System element is that a battery uses chemicals, metal alloys, plastics, welds, and bonds that must interact with each other to produce the constant dc source required for Protection Systems, undisturbed by ac system Disturbances.

No type of battery manufactured today for Protection System application is free from problems that can only be detected over time by inspection and test. These problems can arise from variances in the manufacturing process, chemicals and alloys used in the construction of the individual cells, quality of welds and bonds to connect the components, the plastics used to make batteries and the cell forming process for the individual battery cells.

Other problems that require periodic inspection and testing can result from transportation from the factory to the job site, length of time before a charge is put on the battery, the method of installation, the voltage level and duration of equalize charges, the float voltage level used, and the environment that the battery is installed in.

All of the above mentioned factors and several more not discussed here are beyond the control of the Functional Entities that want to use a Performance-Based Protection System Maintenance (PBM) program. These inherent variances in the aging process of a battery cell make establishment of a designated segment based on manufacturer and type of battery impossible.

The whole point of PBM is that if all variables are isolated then common aging and performance criteria would be the same. However, there are too many variables in the electrochemical process to completely isolate all of the performance-changing criteria.

Similarly, Functional Entities that want to establish a condition-based maintenance program using the highest levels of monitoring, resulting in the least amount of hands-on maintenance activity, cannot completely eliminate some periodic maintenance of the battery used in a station dc supply. Inspection of the battery is required on a Maximum Maintenance Interval listed in the tables due to the aging processes of station batteries. However, higher degrees of

monitoring of a battery can eliminate the requirement for some periodic testing and some inspections (see Table 1-4).

Please provide an example of the calculations involved in extending maintenance time intervals using PBM.

Entity has 1000 GE-HEA lock-out relays; this is greater than the minimum sample requirement of 60. They start out testing all of the relays within the prescribed Table requirements (6 year max) by testing the relays every 5 years. The entity's plan is to test 200 units per year; this is greater than the minimum sample size requirement of 30. For the sake of example only the following will show 6 failures per year, reality may well have different numbers of failures every year. PBM requires annual assessment of failures found per units tested. After the first year of tests the entity finds 6 failures in the 200 units tested. 6/200= 3% failure rate. This entity is now allowed to extend the maintenance interval if they choose. The entity chooses to extend the maintenance interval of this population segment out to 10 years. This represents a rate of 100 units tested per year; entity selects 100 units to be tested in the following year. After that year of testing these 100 units the entity again finds 6 failed units. 6/100= 6% failures. This entity has now exceeded the acceptable failure rate for these devices and must accelerate testing of all of the units at a higher rate such that the failure rate is found to be less than 4% per year; the entity has three years to get this failure rate down to 4% or less (per year). In response to the 6% failure rate, the entity decreases the testing interval to 8 years. This means that they will now test 125 units per year (1000/8). The entity has just two years left to get the test rate corrected.

After a year, they again find six failures out of the 125 units tested. 6/125= 5% failures. In response to the 5% failure rate, the entity decreases the testing interval to seven years. This means that they will now test 143 units per year (1000/7). The entity has just one year left to get the test rate corrected. After a year, they again find six failures out of the 143 units tested. 6/143= 4.2% failures.

(Note that the entity has tried five years and they were under the 4% limit and they tried seven years and they were over the 4% limit. They must be back at 4% failures or less in the next year so they might simply elect to go back to five years.)

Instead, in response to the 5% failure rate, the entity decreases the testing interval to six years. This means that they will now test 167 units per year (1000/6). After a year, they again find six failures out of the 167 units tested. 6/167= 3.6% failures. Entity found that they could maintain the failure rate at no more than 4% failures by maintaining the testing interval at six years or less. Entity chose six-year interval and effectively extended their TBM (five years) program by 20%.

A note of practicality is that an entity will probably be in better shape to lengthen the intervals between tests if the failure rate is less than 2%. But the requirements allow for annual adjustments, if the entity desires. As a matter of maintenance management, an ever-changing test rate (units tested/year) may be un-workable.

Note that the "5% of components" requirement effectively sets a practical limit of 20 year maximum PBM interval. Also of note is the "3 years" requirement; an entity might arbitrarily extend time intervals from six years to 20 years. In the event that an entity finds a failure rate greater than 4%, then the test rate must be accelerated such that within three years the failure rate must be brought back down to 4% or less.

Here is a table that demonstrates the values discussed:

Year #	Total Population (P)	Test Interval (I)	Units to be Tested (U= P/I)	# of Failures Found (F)	Failure Rate (=F/U)	Decision to Change Interval Yes or No	Interval Chosen
1	1000	5 yrs	200	6	3%	Yes	10 yrs
2	1000	10 yrs	100	6	6%	Yes	8 yrs
3	1000	8 yrs	125	6	5%	Yes	7 yrs
4	1000	7 yrs	143	6	4.2%	Yes	6 yrs
5	1000	6 yrs	167	6	3.6%	No	6 yrs

Please provide an example of the calculations involved in extending maintenance time intervals using PBM for control circuitry.

Note that the following example captures "Control Circuitry" as all of the trip paths associated with a particular trip coil of a circuit breaker. An entity is not restricted to this method of counting control circuits. Perhaps another method an entity would prefer would be to simply track every individual (parallel) trip path. Or perhaps another method would be to track all of the trip outputs from a specific (set) of relays protecting a specific element. Under the included definition of "component":

The designation of what constitutes a control circuit component is very dependent upon how an entity performs and tracks the testing of the control circuitry. Some entities test their control circuits on a breaker basis whereas others test their circuitry on a local zone of protection basis. Thus, entities are allowed the latitude to designate their own definitions of control circuit components. Another example of where the entity has some discretion on determining what constitutes a single component is the voltage and current sensing devices, where the entity may choose either to designate a full three-phase set of such devices or a single device as a single component.

And in Attachment A (PBM) the definition of Segment:

Segment –*Components of a consistent design standard, or a particular model or type from a single manufacturer that typically share other common elements. Consistent performance is expected across the entire population of a segment. A segment must contain at least sixty (60) individual components.*

Example:

Entity has 1,000 circuit breakers, all of which have two trip coils, for a total of 2,000 trip coils; if all circuitry was designed and built with a consistent (internal entity) standard, then this is greater than the minimum sample requirement of 60.

For the sake of further example, the following facts are given:

Half of all relay panels (500) were built 40 years ago by an outside contractor, consisted of asbestos wrapped 600V-insulation panel wiring, and the cables exiting the control house are THHN pulled in conduit direct to exactly half of all of the various circuit breakers. All of the relay panels and cable pulls were built with consistent standards and consistent performance standard expectations within the segment (which is greater than 60). Each relay panel has redundant microprocessor (MPC) relays (retrofitted); each MPC relay supplies an individual trip output to each of the two trip coils of the assigned circuit breaker.

Approximately 35 years ago, the entity developed their own internal construction crew and now builds all of their own relay panels from parts supplied from vendors that meet the entity's specifications, including SIS 600V insulation wiring and copper-sheathed cabling within the direct conduits to circuit breakers. The construction crew uses consistent standards in the construction. This newer segment of their control circuitry population is different than the original segment, consistent (standards, construction and performance expectations) within the new segment and constitutes the remainder of the entity's population (another 500 panels and the cabling to the remaining 500 circuit breakers). Each relay panel has redundant microprocessor (MPC) relays; each MPC relay supplies an individual trip output to each of the two trip coils of the assigned circuit breaker. Every trip path in this newer segment has a device that monitors the voltage directly across the trip contacts of the MPC relays and alarms via RTU and SCADA to the operations control room. This monitoring device, when not in alarm, demonstrates continuity all the way through the trip coil, cabling and wiring back to the trip contacts of the MPC relay.

The entity is tracking 2,000 trip coils (each consisting of multiple trip paths) in each of these two segments. But half of all of the trip paths are monitored; therefore, the trip paths are continuously tested and the circuit will alarm when there is a failure. These alarms have to be verified every 12 years for correct operation.

The entity now has 1,000 trip coils (and associated trip paths) remaining that they have elected to count as control circuits. The entity has instituted a process that requires the verification of every trip path to each trip coil (one unit), including the electrical activation of the trip coil. (The entity notes that the trip coils will have to be tripped electrically more often than the trip path verification, and is taking care of this activity through other documentation of Real-time Fault operations.)

They start out testing all of the trip coil circuits within the prescribed Table requirements (12-year max) by testing the trip circuits every 10 years. The entity's plan is to test 100 units per year; this is greater than the minimum sample size requirement of 30. For the sake of example only, the following will show three failures per year; reality may well have different numbers of failures every year. PBM requires annual assessment of failures found per units tested. After the first year of tests, the entity finds three failures in the 100 units tested. 3/100= 3% failure rate.

This entity is now allowed to extend the maintenance interval, if they choose. The entity chooses to extend the maintenance interval of this population segment out to 20 years. This represents a rate of 50 units tested per year; entity selects 50 units to be tested in the following year. After that year of testing these 50 units, the entity again finds three failed units. 3/50= 6% failures.

This entity has now exceeded the acceptable failure rate for these devices and must accelerate testing of all of the units at a higher rate, such that the failure rate is found to be less than 4% per year; the entity has three years to get this failure rate down to 4% or less (per year).

In response to the 6% failure rate, the entity decreases the testing interval to 16 years. This means that they will now test 63 units per year (1000/16). The entity has just two years left to get the test rate corrected. After a year, they again find three failures out of the 63 units tested. 3/63= 4.76% failures.

In response to the >4% failure rate, the entity decreases the testing interval to 14 years. This means that they will now test 72 units per year (1000/14). The entity has just one year left to get the test rate corrected. After a year, they again find three failures out of the 72 units tested. 3/72= 4.2% failures.

(Note that the entity has tried 10 years, and they were under the 4% limit; and they tried 14 years, and they were over the 4% limit. They must be back at 4% failures or less in the next year, so they might simply elect to go back to 10 years.)

Instead, in response to the 4.2% failure rate, the entity decreases the testing interval to 12 years. This means that they will now test 84 units per year (1000/12). After a year, they again find three failures out of the 84 units tested. 3/84= 3.6% failures.

Entity found that they could maintain the failure rate at no more than 4% failures by maintaining the testing interval at 12 years or less. Entity chose 12-year interval, and effectively extended their TBM (10 years) program by 20%.

A note of practicality is that an entity will probably be in better shape to lengthen the intervals between tests if the failure rate is less than 2%. But the requirements allow for annual adjustments if the entity desires. As a matter of maintenance management, an ever-changing test rate (units tested / year) may be un-workable.

Note that the "5% of components" requirement effectively sets a practical limit of 20-year maximum PBM interval. Also of note is the "3 years" requirement; an entity might arbitrarily extend time intervals from six years to 20 years. In the event that an entity finds a failure rate greater than 4%, then the test rate must be accelerated such that within three years the failure rate must be brought back down to 4% or less.

Here is a table that demonstrates the values discussed:

Year #	Total Population (P)	Test Interval (I)	Units to be Tested (U= P/I)	# of Failures Found (F)	Failure Rate (=F/U)	Decision to Change Interval Yes or No	Interval Chosen
1	1000	10 yrs	100	3	3%	Yes	20 yrs
2	1000	20 yrs	50	3	6%	Yes	16yrs
3	1000	16 yrs	63	3	4.8%	Yes	14 yrs
4	1000	14 yrs	72	3	4.2%	Yes	12 yrs
5	1000	12 yrs	84	3	3.6%	No	12 yrs

Please provide an example of the calculations involved in extending maintenance time intervals using PBM for voltage and current sensing devices.

Note that the following example captures "voltage and current inputs to the protective relays" as all of the various current transformer and potential transformer signals associated with a particular set of relays used for protection of a specific Element. This entity calls this set of protective relays a "Relay Scheme." Thus, this entity chooses to count PT and CT signals as a group instead of individually tracking maintenance activities to specific bushing CT's or specific PT's. An entity is not restricted to this method of counting voltage and current devices, signals and paths. Perhaps another method an entity would prefer would be to simply track every individual PT and CT. Note that a generation maintenance group may well select the latter because they may elect to perform routine off-line tests during generator outages, whereas a transmission maintenance group might create a process that utilizes Real-time system values measured at the relays. Under the included definition of "component":

The designation of what constitutes a control circuit component is very dependent upon how an entity performs and tracks the testing of the control circuitry. Some entities test their control circuits on a breaker basis whereas others test their circuitry on a local zone of protection basis. Thus, entities are allowed the latitude to designate their own definitions of control circuit components. Another example of where the entity has some discretion on determining what constitutes a single component is the voltage and current sensing devices, where the entity may choose either to designate a full three-phase set of such devices or a single device as a single component.

And in Attachment A (PBM) the definition of Segment:

Segment –*Components of a consistent design standard, or a particular model or type from a single manufacturer that typically share other common elements. Consistent performance is expected across the entire population of a segment. A segment must contain at least sixty (60) individual components.*

Example:

Entity has 2000 "Relay Schemes," all of which have three current signals supplied from bushing CTs, and three voltage signals supplied from substation bus PT's. All cabling and circuitry was designed and built with a consistent (internal entity) standard, and this population is greater than the minimum sample requirement of 60.

For the sake of further example the following facts are given:

Half of all relay schemes (1,000) are supplied with current signals from ANSI STD C800 bushing CTs and voltage signals from PTs built by ACME Electric MFR CO. All of the relay panels and cable pulls were built with consistent standards, and consistent performance standard expectations exist for the consistent wiring, cabling and instrument transformers within the segment (which is greater than 60).

The other half of the entity's relay schemes have MPC relays with additional monitoring built-in that compare DNP values of voltages and currents (or Watts and VARs), as interpreted by the MPC relays and alarm for an entity-accepted tolerance level of accuracy. This newer segment of their "Voltage and Current Sensing" population is different than the original segment, consistent (standards, construction and performance expectations) within the new segment and constitutes the remainder of the entity's population.

The entity is tracking many thousands of voltage and current signals within 2,000 relay schemes (each consisting of multiple voltage and current signals) in each of these two segments. But half of all of the relay schemes voltage and current signals are monitored; therefore, the voltage and current signals are continuously tested and the circuit will alarm when there is a failure; these alarms have to be verified every 12 years for correct operation.

The entity now has 1,000 relay schemes worth of voltage and current signals remaining that they have elected to count within their relay schemes designation. The entity has instituted a process that requires the verification of these voltage and current signals within each relay scheme (one unit).

(Please note - a problem discovered with a current or voltage signal found at the relay could be caused by anything from the relay, all the way to the signal source itself. Having many sources of problems can easily increase failure rates beyond the rate of failures of just one item (for example just PTs). It is the intent of the SDT to minimize failure rates of all of the equipment to an acceptable level; thus, any failure of any item that gets the signal from source to relay is counted. It is for this reason that the SDT chose to set the boundary at the ability of the signal to be delivered all the way to the relay.

The entity will start out measuring all of the relay scheme voltage and currents at the individual relays within the prescribed Table requirements (12 year max) by measuring the voltage and current values every 10 years. The entity's plan is to test 100 units per year; this is greater than the minimum sample size requirement of 30. For the sake of example only, the following will show three failures per year; reality may well have different numbers of failures every year. PBM requires annual assessment of failures found per units tested. After the first year of tests, the entity finds three failures in the 100 units tested. 3/100= 3% failure rate.

This entity is now allowed to extend the maintenance interval, if they choose. The entity chooses to extend the maintenance interval of this population segment out to 20 years. This represents a rate of 50 units tested per year; entity selects 50 units to be tested in the following year. After that year of testing these 50 units, the entity again finds three failed units. 3/50= 6% failures.

This entity has now exceeded the acceptable failure rate for these devices and must accelerate testing of all of the units at a higher rate, such that the failure rate is found to be less than 4% per year; the entity has three years to get this failure rate down to 4% or less (per year).

In response to the 6% failure rate, the entity decreases the testing interval to 16 years. This means that they will now test 63 units per year (1000/16). The entity has just two years left to get the test rate corrected. After a year, they again find three failures out of the 63 units tested. 3/63= 4.76% failures.

In response to the >4%failure rate, the entity decreases the testing interval to 14 years. This means that they will now test 72 units per year (1000/14). The entity has just one year left to get the test rate corrected. After a year, they again find three failures out of the 72 units tested. 3/72= 4.2% failures.

(Note that the entity has tried 10 years, and they were under the 4% limit; and they tried 14 years, and they were over the 4% limit. They must be back at 4% failures or less in the next year, so they might simply elect to go back to 10 years.)

Instead, in response to the 4.2% failure rate, the entity decreases the testing interval to 12 years. This means that they will now test 84 units per year (1,000/12). After a year, they again find three failures out of the 84 units tested. 3/84= 3.6% failures.

Entity found that they could maintain the failure rate at no more than 4% failures by maintaining the testing interval at 12 years or less. Entity chose 12-year interval and effectively extended their TBM (10 years) program by 20%.

A note of practicality is that an entity will probably be in better shape to lengthen the intervals between tests if the failure rate is less than 2%. But the requirements allow for annual adjustments, if the entity desires. As a matter of maintenance management, an ever-changing test rate (units tested/year) may be un-workable.

Note that the “5% of components” requirement effectively sets a practical limit of 20-year maximum PBM interval. Also of note is the “3 years” requirement; an entity might arbitrarily extend time intervals from six years to 20 years. In the event that an entity finds a failure rate greater than 4%, then the test rate must be accelerated such that within three years the failure rate must be brought back down to 4% or less.

Here is a table that demonstrates the values discussed:

Year #	Total Population (P)	Test Interval (I)	Units to be Tested (U= P/I)	# of Failures Found (F)	Failure Rate (=F/U)	Decision to Change Interval Yes or No	Interval Chose
1	1000	10 yrs	100	3	3%	Yes	20 yrs
2	1000	20 yrs	50	3	6%	Yes	16yrs
3	1000	16 yrs	63	3	4.8%	Yes	14 yrs
4	1000	14 yrs	72	3	4.2%	Yes	12 yrs
5	1000	12 yrs	84	3	3.6%	No	12 yrs

10. Overlapping the Verification of Sections of the Protection System

Tables 1-1 through 1-5 require that every Protection System component be periodically verified. One approach, but not the only method, is to test the entire protection scheme as a unit, from the secondary windings of voltage and current sources to breaker tripping. For practical ongoing verification, sections of the Protection System may be tested or monitored individually. The boundaries of the verified sections must overlap to ensure that there are no gaps in the verification. See Appendix A of this Supplementary Reference for additional discussion on this topic.

All of the methodologies expressed within this report may be combined by an entity, as appropriate, to establish and operate a maintenance program. For example, a Protection System may be divided into multiple overlapping sections with a different maintenance methodology for each section:

- Time-based maintenance with appropriate maximum verification intervals for categories of equipment, as given in the Tables 1-1 through 1-5;
- Monitoring as described in Tables 1-1 through 1-5;
- A Performance-Based Maintenance program as described in Section 9 above, or Attachment A of the standard;
- Opportunistic verification using analysis of Fault records, as described in Section 11

10.1 Frequently Asked Questions:

My system has alarms that are gathered once daily through an auto-polling system; this is not really a conventional SCADA system but does it meet the Table 1 requirements for inclusion as a monitored system?

Yes, provided the auto-polling that gathers the alarms reports those alarms to a location where the action can be initiated to correct the Unresolved Maintenance Issue. This location does not have to be the location of the engineer or the technician that will eventually repair the problem, but rather a location where the action can be initiated.

11. Monitoring by Analysis of Fault Records

Many users of microprocessor relays retrieve Fault event records and oscillographic records by data communications after a Fault. They analyze the data closely if there has been an apparent Misoperation, as NERC standards require. Some advanced users have commissioned automatic Fault record processing systems that gather and archive the data. They search for evidence of component failures or setting problems hidden behind an operation whose overall outcome seems to be correct. The relay data may be augmented with independently captured Digital Fault Recorder (DFR) data retrieved for the same event.

Fault data analysis comprises a legitimate CBM program that is capable of reducing the need for a manual time-interval based check on Protection Systems whose operations are analyzed. Even electromechanical Protection Systems instrumented with DFR channels may achieve some CBM benefit. The completeness of the verification then depends on the number and variety of Faults in the vicinity of the relay that produce relay response records and the specific data captured.

A typical Fault record will verify particular parts of certain Protection Systems in the vicinity of the Fault. For a given Protection System installation, it may or may not be possible to gather within a reasonable amount of time an ensemble of internal and external Fault records that completely verify the Protection System.

For example, Fault records may verify that the particular relays that tripped are able to trip via the control circuit path that was specifically used to clear that Fault. A relay or DFR record may indicate correct operation of the protection communications channel. Furthermore, other nearby Protection Systems may verify that they restrain from tripping for a Fault just outside their respective zones of protection. The ensemble of internal Fault and nearby external Fault event data can verify major portions of the Protection System, and reset the time clock for the Table 1 testing intervals for the verified components only.

What can be shown from the records of one operation is very specific and limited. In a panel with multiple relays, only the specific relay(s) whose operation can be observed without ambiguity should be used. Be careful about using Fault response data to verify that settings or calibration are correct. Unless records have been captured for multiple Faults close to either side of a setting boundary, setting or calibration could still be incorrect.

PMU data, much like DME data, can be utilized to prove various components of the Protection System. Obviously, care must be taken to attribute proof only to the parts of a Protection System that can actually be proven using the PMU or DME data.

If Fault record data is used to show that portions or all of a Protection System have been verified to meet Table 1 requirements, the owner must retain the Fault records used, and the maintenance-related conclusions drawn from this data and used to defer Table 1 tests, for at least the retention time interval given in Section 8.2.

11.1 Frequently Asked Questions:

I use my protective relays for Fault and Disturbance recording, collecting oscillographic records and event records via communications for Fault analysis to meet NERC and DME requirements. What are the maintenance requirements for the relays?

For relays used only as Disturbance Monitoring Equipment, NERC Standard PRC-018-1 R3 & R6 states the maintenance requirements and is being addressed by a standards activity that is revising PRC-002-1 and PRC-018-1. For protective relays "that are designed to provide protection for the BES," this standard applies, even if they also perform DME functions.

12. Importance of Relay Settings in Maintenance Programs

In manual testing programs, many utilities depend on pickup value or zone boundary tests to show that the relays have correct settings and calibration. Microprocessor relays, by contrast, provide the means for continuously monitoring measurement accuracy. Furthermore, the relay digitizes inputs from one set of signals to perform all measurement functions in a single self-monitoring microprocessor system. These relays do not require testing or calibration of each setting.

However, incorrect settings may be a bigger risk with microprocessor relays than with older relays. Some microprocessor relays have hundreds or thousands of settings, many of which are critical to Protection System performance.

Monitoring does not check measuring element settings. Analysis of Fault records may or may not reveal setting problems. To minimize risk of setting errors after commissioning, the user should enforce strict settings data base management, with reconfirmation (manual or automatic) that the installed settings are correct whenever maintenance activity might have changed them; for background and guidance, see [5] in References.

Table 1 requires that settings must be verified to be as specified. The reason for this requirement is simple: With legacy relays (non-microprocessor protective relays), it is necessary to know the value of the intended setting in order to test, adjust and calibrate the relay. Proving that the relay works per specified setting was the de facto procedure. However, with the advanced microprocessor relays, it is possible to change relay settings for the purpose of verifying specific functions and then neglect to return the settings to the specified values. While there is no specific requirement to maintain a settings management process, there remains a need to verify that the settings left in the relay are the intended, specified settings. This need may manifest itself after any of the following:

- One or more settings are changed for any reason.
- A relay fails and is repaired or replaced with another unit.
- A relay is upgraded with a new firmware version.

12.1 Frequently Asked Questions:

How do I approach testing when I have to upgrade firmware of a microprocessor relay?

The entity should ensure that the relay continues to function properly after implementation of firmware changes. Some entities may have a R&D department that might routinely run acceptance tests on devices with firmware upgrades before allowing the upgrade to be installed. Other entities may rely upon the vigorous testing of the firmware OEM. An entity has the latitude to install devices and/or programming that they believe will perform to their satisfaction. If an entity should choose to perform the maintenance activities specified in the Tables following a firmware upgrade, then they may, if they choose, reset the time clock on that set of maintenance activities so that they would not have to repeat the maintenance on its regularly scheduled cycle.

(However, for simplicity in maintenance schedules, some entities may choose to not reset this time clock; it is merely a suggested option.)

If I upgrade my old relays, then do I have to maintain my previous equipment maintenance documentation?

If an equipment item is repaired or replaced, then the entity can restart the maintenance-activity-time-interval-clock, if desired; however, the replacement of equipment does not remove any documentation requirements. The requirements in the standard are intended to ensure that an entity has a maintenance plan, and that the entity adheres to minimum activities and maximum time intervals. The documentation requirements are intended to help an entity demonstrate compliance. For example, saving the dates and records of the last two maintenance activities is intended to demonstrate compliance with the interval. Therefore, if you upgrade or replace equipment, then you still must maintain the documentation for the previous equipment, thus demonstrating compliance with the time interval requirement prior to the replacement action.

We have a number of installations where we have changed our Protection System components. Some of the changes were upgrades, but others were simply system rating changes that merely required taking relays "out-of-service". What are our responsibilities when it comes to "out-of-service" devices?

Assuming that your system up-rates, upgrades and overall changes meet any and all other requirements and standards, then the requirements of PRC-005-X are simple – if the Protection System component performs a Protection System function, then it must be maintained. If the component no longer performs Protection System functions, then it does not require maintenance activities under the Tables of PRC-005-X. While many entities might physically remove a component that is no longer needed, there is no requirement in PRC-005-X to remove such component(s). Obviously, prudence would dictate that an "out-of-service" device is truly made inactive. There are no record requirements listed in PRC-005-X for Protection System components not used.

While performing relay testing of a protective device on our Bulk Electric System, it was discovered that the protective device being tested was either broken or out of calibration. Does this satisfy the relay testing requirement, even though the protective device tested bad, and may be unable to be placed back into service?

Yes, PRC-005-X requires entities to perform relay testing on protective devices on a given maintenance cycle interval. By performing this testing, the entity has satisfied PRC-005-X requirement, although the protective device may be unable to be returned to service under normal calibration adjustments. R5 states:

"R5. Each Transmission Owner, Generator Owner, and Distribution Provider shall demonstrate efforts to correct any identified Unresolved Maintenance Issues."

Also, when a failure occurs in a Protection System, power system security may be comprised, and notification of the failure must be conducted in accordance with relevant NERC standards.

If I show the protective device out of service while it is being repaired, then can I add it back as a new protective device when it returns? If not, my relay testing history would show that I was out of compliance for the last maintenance cycle.

The maintenance and testing requirements (R5) state "…shall demonstrate efforts to correct any identified Unresolved Maintenance Issues..." The type of corrective activity is not stated; however, it could include repairs or replacements.

Your documentation requirements will increase, of course, to demonstrate that your device tested bad and had corrective actions initiated. Your regional entity might ask about the status of your corrective actions.

13. Self-Monitoring Capabilities and Limitations

Microprocessor relay proponents have cited the self-monitoring capabilities of these products for nearly 20 years. Theoretically, any element that is monitored does not need a periodic manual test. A problem today is that the community of manufacturers and users has not created clear documentation of exactly what is and is not monitored. Some unmonitored but critical elements are buried in installed systems that are described as self-monitoring.

To utilize the extended time intervals allowed by monitoring, the user must document that the monitoring attributes of the device match the minimum requirements listed in the Table 1.

Until users are able to document how all parts of a system which are required for the protective functions are monitored or verified (with help from manufacturers), they must continue with the unmonitored intervals established in Table 1 and Table 3.

Going forward, manufacturers and users can develop mappings of the monitoring within relays, and monitoring coverage by the relay of user circuits connected to the relay terminals.

To enable the use of the most extensive monitoring (and never again have a hands-on maintenance requirement), the manufacturers of the microprocessor-based self-monitoring components in the Protection System should publish for the user a document or map that shows:

- How all internal elements of the product are monitored for any failure that could impact Protection System performance.
- Which connected circuits are monitored by checks implemented within the product; how to connect and set the product to assure monitoring of these connected circuits; and what circuits or potential problems are not monitored.

This manufacturer's information can be used by the registered entity to document compliance of the monitoring attributes requirements by:

- Presenting or referencing the product manufacturer's documents.
- Explaining in a system design document the mapping of how every component and circuit that is critical to protection is monitored by the microprocessor product(s) or by other design features.
- Extending the monitoring to include the alarm transmission Facilities through which failures are reported within a given time frame to allocate where action can be taken to initiate resolution of the alarm attributed to an Unresolved Maintenance Issue, so that failures of monitoring or alarming systems also lead to alarms and action.
- Documenting the plans for verification of any unmonitored components according to the requirements of Table 1 and Table 3.

13.1 Frequently Asked Questions:

I can't figure out how to demonstrate compliance with the requirements for the highest level of monitoring of Protection Systems. Why does this Maintenance Standard describe a maintenance program approach I cannot achieve?

Demonstrating compliance with the requirements for the highest level of monitoring any particular component of Protection Systems is likely to be very involved, and may include detailed manufacturer documentation of complete internal monitoring within a device, comprehensive design drawing reviews, and other detailed documentation. This standard does not presume to specify what documentation must be developed; only that it must be documented.

There may actually be some equipment available that is capable of meeting these highest levels of monitoring criteria, in which case it may be maintained according to the highest level of monitoring shown on the Tables. However, even if there is no equipment available today that can meet this level of monitoring, the standard establishes the necessary requirements for when such equipment becomes available.

By creating a roadmap for development, this provision makes the standard technology-neutral. The Standard Drafting Team wants to avoid the need to revise the standard in a few years to accommodate technology advances that may be coming to the industry.

14. Notification of Protection System or Automatic Reclosing Failures

When a failure occurs in a Protection System or Automatic Reclosing, power system security may be compromised, and notification of the failure must be conducted in accordance with relevant NERC standard(s). Knowledge of the failure may impact the system operator's decisions on acceptable Loading conditions.

This formal reporting of the failure and repair status to the system operator by the Protection System or Automatic Reclosing owner also encourages the system owner to execute repairs as rapidly as possible. In some cases, a microprocessor relay or carrier set can be replaced in hours; wiring termination failures may be repaired in a similar time frame. On the other hand, a component in an electromechanical or early-generation electronic relay may be difficult to find and may hold up repair for weeks. In some situations, the owner may have to resort to a temporary protection panel, or complete panel replacement.

15. Maintenance Activities

Some specific maintenance activities are a requirement to ensure reliability. An example would be that a BES entity could be prudent in its protective relay maintenance, but if its battery maintenance program is lacking, then reliability could still suffer. The NERC glossary outlines a Protection System as containing specific components. PRC-005-X requires specific maintenance activities be accomplished within a specific time interval. As noted previously, higher technology equipment can contain integral monitoring capability that actually performs maintenance verification activities routinely and often; therefore, *manual intervention* to perform certain activities on these type components may not be needed.

15.1 Protective Relays (Table 1-1)

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 Element of the BES. Devices that sense thermal, vibration, seismic, gas, or any other non-electrical inputs are excluded.

Non-microprocessor based equipment is treated differently than microprocessor-based equipment in the following ways; the relays should meet the asset owners' tolerances:

- Non-microprocessor devices must be tested with voltage and/or current applied to the device.
- Microprocessor devices may be tested through the integral testing of the device.
    - There is no specific protective relay commissioning test or relay routine test mandated.
    - There is no specific documentation mandated.

15.1.1 Frequently Asked Questions:

What calibration tolerance should be applied on electromechanical relays?

Each entity establishes their own acceptable tolerances when applying protective relaying on their system. For some Protection System components, adjustment is required to bring measurement accuracy within the parameters established by the asset owner based on the specific application of the component. A calibration failure is the result if testing finds the specified parameters to be out of tolerance.

15.2 Voltage & Current Sensing Devices (Table 1-3)

These are the current and voltage sensing devices, usually known as instrument transformers. There is presently a technology available (fiber-optic Hall-effect) that does not utilize conventional transformer technology; these devices and other technologies that produce quantities that represent the primary values of voltage and current are considered to be a type of voltage and current sensing devices included in this standard.

The intent of the maintenance activity is to verify the input to the protective relay from the device that produces the current or voltage signal sample.

There is no specific test mandated for these components. The important thing about these signals is to know that the expected output from these components actually reaches the protective relay. Therefore, the proof of the proper operation of these components also demonstrates the integrity of the wiring (or other medium used to convey the signal) from the current and voltage sensing device, all the way to the protective relay. The following observations apply:

- There is no specific ratio test, routine test or commissioning test mandated.
- There is no specific documentation mandated.
- It is required that the signal be present at the relay.
- This expectation can be arrived at from any of a number of means; including, but not limited to, the following: By calculation, by comparison to other circuits, by commissioning tests, by thorough inspection, or by any means needed to verify the circuit meets the asset owner's Protection System maintenance program.
- An example of testing might be a saturation test of a CT with the test values applied at the relay panel; this, therefore, tests the CT, as well as the wiring from the relay all the back to the CT.
- Another possible test is to measure the signal from the voltage and/or current sensing devices, during Load conditions, at the input to the relay.
- Another example of testing the various voltage and/or current sensing devices is to query the microprocessor relay for the Real-time Loading; this can then be compared to other devices to verify the quantities applied to this relay. Since the input devices have supplied the proper values to the protective relay, then the verification activity has been satisfied. Thus, event reports (and oscillographs) can be used to verify that the voltage and current sensing devices are performing satisfactorily.
- Still another method is to measure total watts and VArs around the entire bus; this should add up to zero watts and zero VArs, thus proving the voltage and/or current sensing devices system throughout the bus.
- Another method for proving the voltage and/or current-sensing devices is to complete commissioning tests on all of the transformers, cabling, fuses and wiring.
- Any other method that verifies the input to the protective relay from the device that produces the current or voltage signal sample.

15.2.1 Frequently Asked Questions:

What is meant by "…verify the current and voltage circuit inputs from the voltage and current sensing devices to the protective relays …" Do we need to perform ratio, polarity and saturation tests every few years?

No. You must verify that the protective relay is receiving the expected values from the voltage and current-sensing devices (typically voltage and current transformers). This can be as difficult as is proposed by the question (with additional testing on the cabling and substation wiring to ensure that the values arrive at the relays); or simplicity can be achieved by other verification methods. While some examples follow, these are not intended to represent an all-inclusive list; technology advances and ingenuity should not be excluded from making comparisons and verifications:

- Compare the secondary values, at the relay, to a metering circuit, fed by different current transformers, monitoring the same line as the questioned relay circuit.
- Compare the individual phase secondary values at the relay panel (with additional testing on the panel wiring to ensure that the values arrive at those relays) with the other phases, and verify that residual currents are within expected bounds.
- Observe all three phase currents and the residual current at the relay panel with an oscilloscope, observing comparable magnitudes and proper phase relationship, with additional testing on the panel wiring to ensure that the values arrive at the relays.
- Compare the values, as determined by the questioned relay (such as, but not limited to, a query to the microprocessor relay) to another protective relay monitoring the same line, with currents supplied by different CTs.
- Compare the secondary values, at the relay with values measured by test instruments (such as, but not limited to multi-meters, voltmeter, clamp-on ammeters, etc.) and verified by calculations and known ratios to be the values expected. For example, a single PT on a 100KV bus will have a specific secondary value that, when multiplied by the PT ratio, arrives at the expected bus value of 100KV.
- Query SCADA for the power flows at the far end of the line protected by the questioned relay, compare those SCADA values to the values as determined by the questioned relay.
- Totalize the Watts and VARs on the bus and compare the totals to the values as seen by the questioned relay.

The point of the verification procedure is to ensure that all of the individual components are functioning properly; and that an ongoing proactive procedure is in place to re-check the various components of the protective relay measuring Systems.

Is wiring insulation or hi-pot testing required by this Maintenance Standard?

No, wiring insulation and equipment hi-pot testing are not specifically required by the Maintenance Standard. However, if the method of verifying CT and PT inputs to the relay involves some other method than actual observation of current and voltage transformer secondary inputs to the relay, it might be necessary to perform some sort of cable integrity test to verify that the instrument transformer secondary signals are actually making it to the relay and not being shunted off to ground. For instance, you could use CT excitation tests and PT turns ratio tests

and compare to baseline values to verify that the instrument transformer outputs are acceptable. However, to conclude that these acceptable transformer instrument output signals are actually making it to the relay inputs, it also would be necessary to verify the insulation of the wiring between the instrument transformer and the relay.

My plant generator and transformer relays are electromechanical and do not have metering functions, as do microprocessor- based relays. In order for me to compare the instrument transformer inputs to these relays to the secondary values of other metered instrument transformers monitoring the same primary voltage and current signals, it would be necessary to temporarily connect test equipment, like voltmeters and clamp on ammeters, to measure the input signals to the relays. This practice seems very risky, and a plant trip could result if the technician were to make an error while measuring these current and voltage signals. How can I avoid this risk? Also, what if no other instrument transformers are available which monitor the same primary voltage or current signal?

Comparing the input signals to the relays to the outputs of other independent instrument transformers monitoring the same primary current or voltage is just one method of verifying the instrument transformer inputs to the relays, but is not required by the standard. Plants can choose how to best manage their risk. If online testing is deemed too risky, offline tests, such as, but not limited to, CT excitation test and PT turns ratio tests can be compared to baseline data and be used in conjunction with CT and PT secondary wiring insulation verification tests to adequately "verify the current and voltage circuit inputs from the voltage and current sensing devices to the protective relays …" while eliminating the risk of tripping an in service generator or transformer. Similarly, this same offline test methodology can be used to verify the relay input voltage and current signals to relays when there are no other instrument transformers monitoring available for purposes of signal comparison.

15.3 Control circuitry associated with protective functions (Table 1-5)

This component of Protection Systems includes the trip coil(s) of the circuit breaker, circuit switcher or any other interrupting device. It includes the wiring from the batteries to the relays. It includes the wiring (or other signal conveyance) from every trip output to every trip coil. It includes any device needed for the correct processing of the needed trip signal to the trip coil of the interrupting device; this requirement is meant to capture inputs and outputs to and from a protective relay that are necessary for the correct operation of the protective functions. In short, every trip path must be verified; the method of verification is optional to the asset owner. An example of testing methods to accomplish this might be to verify, with a volt-meter, the existence of the proper voltage at the open contacts, the open circuited input circuit and at the trip coil(s). As every parallel trip path has similar failure modes, each trip path from relay to trip coil must be verified. Each trip coil must be tested to trip the circuit breaker (or other interrupting device) at least once. There is a requirement to operate the circuit breaker (or other interrupting device) at least once every six years as part of the complete functional test. If a suitable monitoring system is installed that verifies every parallel trip path, then the manual-intervention testing of those parallel trip paths can be eliminated; however, the actual operation of the circuit breaker must still occur at least once every six years. This six-year tripping requirement can be completed as easily as tracking the Real-time Fault-clearing operations on the circuit breaker, or tracking the trip coil(s) operation(s) during circuit breaker routine maintenance actions.

The circuit-interrupting device should not be confused with a motor-operated disconnect. The intent of this standard is to require maintenance intervals and activities on Protection Systems equipment, and not just all system isolating equipment.

It is necessary, however, to classify a device that actuates a high-speed auto-closing ground switch as an interrupting device, if this ground switch is utilized in a Protection System and forces a ground Fault to occur that then results in an expected Protection System operation to clear the forced ground Fault. The SDT believes that this is essentially a transferred-tripping device without the use of communications equipment. If this high-speed ground switch is "…designed to provide protection for the BES…" then this device needs to be treated as any other Protection System component. The control circuitry would have to be tested within 12 years, and any electromechanically operated device will have to be tested every six years. If the spring-operated ground switch can be disconnected from the solenoid triggering unit, then the solenoid triggering unit can easily be tested without the actual closing of the ground blade.

The dc control circuitry also includes each auxiliary tripping relay (94) and each lock-out relay (86) that may exist in any particular trip scheme. If the lock-out relays (86) are electromechanical type components, then they must be trip tested. The PSMT SDT considers these components to share some similarities in failure modes as electromechanical protective relays; as such, there is a six-year maximum interval between mandated maintenance tasks unless PBM is applied.

Contacts of the 86 and/or 94 that pass the trip current on to the circuit interrupting device trip coils will have to be checked as part of the 12 year requirement. Contacts of the 86 and/or 94 lock relay that operate non-BES interrupting devices are not required. Normally-open contacts that are not used to pass a trip signal and normally-closed contacts do not have to be verified. Verification of the tripping paths is the requirement.

New technology is also accommodated here; there are some tripping systems that have replaced the traditional hard-wired trip circuitry with other methods of trip-signal conveyance such as fiber-optics. It is the intent of the PSMT SDT to include this, and any other, technology that is used to convey a trip signal from a protective relay to a circuit breaker (or other interrupting device) within this category of equipment. The requirement for these systems is verification of the tripping path.

Monitoring of the control circuit integrity allows for no maintenance activity on the control circuit (excluding the requirement to operate trip coils and electromechanical lockout and/or tripping auxiliary relays). Monitoring of integrity means to monitor for continuity and/or presence of voltage on each trip path. For Ethernet or fiber-optic control systems, monitoring of integrity means to monitor communication ability between the relay and the circuit breaker.

15.3.1 Frequently Asked Questions:

Is it permissible to verify circuit breaker tripping at a different time (and interval) than when we verify the protective relays and the instrument transformers?

Yes, provided the entire Protective System is tested within the individual component's maximum allowable testing intervals.

The Protection System Maintenance Standard describes requirements for verifying the tripping of circuit breakers. What is this telling me about maintenance of circuit breakers?

Requirements in PRC-005-X are intended to verify the integrity of tripping circuits, including the breaker trip coil, as well as the presence of auxiliary supply (usually a battery) for energizing the trip coil if a protection function operates. Beyond this, PRC-005-X sets no requirements for verifying circuit breaker performance, or for maintenance of the circuit breaker.

How do I test each dc Control Circuit trip path, as established in Table 1-5 "Protection System Control Circuitry (Trip coils and auxiliary relays)"?

Table 1-5 specifies that each breaker trip coil and lockout relays that carry trip current to a trip coil must be operated within the specified time period. The required operations may be via targeted maintenance activities, or by documented operation of these devices for other purposes such as Fault clearing.

Are high-speed ground switch trip coils included in the dc control circuitry?

Yes. PRC-005-X includes high-speed grounding switch trip coils within the dc control circuitry to the degree that the initiating Protection Systems are characterized as "transmission Protection Systems."

Does the control circuitry and trip coil of a non-BES breaker, tripped via a BES protection component, have to be tested per Table 1.5? (Refer to Table 3 for examples 1 and 2) Example 1: A non-BES circuit breaker that is tripped via a Protection System to which PRC-005-X applies might be (but is not limited to) a 12.5KV circuit breaker feeding (non-black-start) radial Loads but has a trip that originates from an under-frequency (81) relay.

- The relay must be verified.
- The voltage signal to the relay must be verified.
- All of the relevant dc supply tests still apply.
- The unmonitored trip circuit between the relay and any lock-out or auxiliary relay must be verified every 12 years.
- The unmonitored trip circuit between the lock-out (or auxiliary relay) and the non-BES breaker does not have to be proven with an electrical trip.
- In the case where there is no lock-out or auxiliary tripping relay used, the trip circuit to the non-BES breaker does not have to be proven with an electrical trip.
- The trip coil of the non-BES circuit breaker does not have to be individually proven with an electrical trip.

Example 2: A Transmission Owner may have a non-BES breaker that is tripped via a Protection System to which PRC-005-X applies, which may be (but is not limited to) a 13.8 KV circuit breaker feeding (non-black-start) radial Loads but has a trip that originates from a BES 115KV line relay.

- The relay must be verified
- The voltage signal to the relay must be verified
- All of the relevant dc supply tests still apply
- The unmonitored trip circuit between the relay and any lock-out (86) or auxiliary (94) relay must be verified every 12 years

- The unmonitored trip circuit between the lock-out (86) (or auxiliary (94)) relay and the non-BES breaker does not have to be proven with an electrical trip
- In the case where there is no lockout (86) or auxiliary (94) tripping relay used, the trip circuit to the non-BES breaker does not have to be proven with an electrical trip.
- The trip coil of the non-BES circuit breaker does not have to be individually proven with an electrical trip

Example 3: A Generator Owner may have a non-BES circuit breaker that is tripped via a Protection System to which PRC-005-X applies, such as the generator field breaker and low-side breakers on station service/excitation transformers connected to the generator bus.

Trip testing of the generator field breaker and low side station service/excitation transformer breaker(s) via lockout or auxiliary tripping relays are not required since these breakers may be associated with radially fed loads and are not considered to be BES breakers. An example of an otherwise non-BES circuit breaker that is tripped via a BES protection component might be (but is not limited to) a 6.9kV station service transformer source circuit breaker but has a trip that originates from a generator differential (87) relay.

- The differential relay must be verified.
- The current signals to the relay must be verified.
- All of the relevant dc supply tests still apply.
- The unmonitored trip circuit between the relay and any lock-out or auxiliary relay must be verified every 12 years.
- The unmonitored trip circuit between the lock-out (or auxiliary relay) and the non-BES breaker does not have to be proven with an electrical trip.
- In the case where there is no lock-out or auxiliary tripping relay used, the trip circuit to the non-BES breaker does not have to be proven with an electrical trip.
- The trip coil of the non-BES circuit breaker does not have to be individually proven with an electrical trip.

However, it is very prudent to verify the tripping of such breakers for the integrity of the overall generation plant.

Do I have to verify operation of breaker "a" contacts or any other normally closed auxiliary contacts in the trip path of each breaker as part of my control circuit test?

Operation of normally-closed contacts does not have to be verified. Verification of the tripping paths is the requirement. The continuity of the normally closed contacts will be verified when the tripping path is verified.

15.4 Batteries and DC Supplies (Table 1-4)

The NERC definition of a Protection System is:

- Protective relays which respond to electrical quantities,
- Communications Systems necessary for correct operation of protective functions,
- Voltage and current sensing devices providing inputs to protective relays,

- Station dc supply associated with protective functions (including station batteries, battery chargers, and non-battery-based dc supply), and
- Control circuitry associated with protective functions through the trip coil(s) of the circuit breakers or other interrupting devices.

The station battery is not the only component that provides dc power to a Protection System. In the new definition for Protection System, “station batteries” are replaced with “station dc supply” to make the battery charger and dc producing stored energy devices (that are not a battery) part of the Protection System that must be maintained.

The PSMT SDT recognizes that there are several technological advances in equipment and testing procedures that allow the owner to choose how to verify that a battery string is free of open circuits. The term “continuity” was introduced into the standard to allow the owner to choose how to verify continuity of a battery set by various methods, and not to limit the owner to other conventional methods of showing continuity. Continuity, as used in Table 1-4 of the standard, refers to verifying that there is a continuous current path from the positive terminal of the station battery set to the negative terminal. Without verifying continuity of a station battery, there is no way to determine that the station battery is available to supply dc power to the station. An open battery string will be an unavailable power source in the event of loss of the battery charger.

Batteries cannot be a unique population segment of a Performance-Based Maintenance Program (PBM) because there are too many variables in the electrochemical process to completely isolate all of the performance-changing criteria necessary for using PBM on battery Systems. However, nothing precludes the use of a PBM process for any other part of a dc supply besides the batteries themselves.

15.4.1 Frequently Asked Questions:

What constitutes the station dc supply, as mentioned in the definition of Protective System?

The previous definition of Protection System includes batteries, but leaves out chargers. The latest definition includes chargers, as well as dc systems that do not utilize batteries. This revision of PRC-005-X is intended to capture these devices that were not included under the previous definition. The station direct current (dc) supply normally consists of two components: the battery charger and the station battery itself. There are also emerging technologies that provide a source of dc supply that does not include either a battery or charger.

<u>Battery Charger</u> - The battery charger is supplied by an available ac source. At a minimum, the battery charger must be sized to charge the battery (after discharge) and supply the constant dc load. In many cases, it may be sized also to provide sufficient dc current to handle the higher energy requirements of tripping breakers and switches when actuated by the protective relays in the Protection System.

<u>Station Battery</u> - Station batteries provide the dc power required for tripping and for supplying normal dc power to the station in the event of loss of the battery charger. There are several technologies of battery that require unique forms of maintenance as established in Table 1-4.

<u>Emerging Technologies</u> - Station dc supplies are currently being developed that use other energy storage technologies besides the station battery to prevent loss of the station dc supply when ac

power is lost. Maintenance of these station dc supplies will require different kinds of tests and inspections. Table 1-4 presents maintenance activities and maximum allowable testing intervals for these new station dc supply technologies. However, because these technologies are relatively new, the maintenance activities for these station dc supplies may change over time.

What did the PSMT SDT mean by "continuity" of the dc supply?

The PSMT SDT recognizes that there are several technological advances in equipment and testing procedures that allow the owner to choose how to verify that a battery string is free of open circuits. The term "continuity" was introduced into the standard to allow the owner to choose how to verify continuity (no open circuits) of a battery set by various methods, and not to limit the owner to other conventional methods of showing continuity – lack of an open circuit. Continuity, as used in Table 1-4 of the standard, refers to verifying that there is a continuous current path from the positive terminal of the station battery set to the negative terminal (no open circuit). Without verifying continuity of a station battery, there is no way to determine that the station battery is available to supply dc power to the station. Whether it is caused from an open cell or a bad external connection, an open battery string will be an unavailable power source in the event of loss of the battery charger.

The current path through a station battery from its positive to its negative connection to the dc control circuits is composed of two types of elements. These path elements are the electrochemical path through each of its cells and all of the internal and external metallic connections and terminations of the batteries in the battery set. If there is loss of continuity (an open circuit) in any part of the electrochemical or metallic path, the battery set will not be available for service. In the event of the loss of the ac source or battery charger, the battery must be capable of supplying dc current, both for continuous dc loads and for tripping breakers and switches. Without continuity, the battery cannot perform this function.

At generating stations and large transmission stations where battery chargers are capable of handling the maximum current required by the Protection System, there are still problems that could potentially occur when the continuity through the connected battery is interrupted.

- Many battery chargers produce harmonics which can cause failure of dc power supplies in microprocessor-based protective relays and other electronic devices connected to station dc supply. In these cases, the substation battery serves as a filter for these harmonics. With the loss of continuity in the battery, the filter provided by the battery is no longer present.
- Loss of electrical continuity of the station battery will cause, in most battery chargers, regardless of the battery charger's output current capability, a delayed response in full output current from the charger. Almost all chargers have an intentional one- to two-second delay to switch from a low substation dc load current to the maximum output of the charger. This delay would cause the opening of circuit breakers to be delayed, which could violate system performance standards.

Monitoring of the station dc supply voltage will not indicate that there is a problem with the dc current path through the battery, unless the battery charger is taken out of service. At that time, a break in the continuity of the station battery current path will be revealed because there will be no voltage on the station dc circuitry. This particular test method, while proving battery continuity, may not be acceptable to all installations.

Although the standard prescribes what must be accomplished during the maintenance activity, it does not prescribe how the maintenance activity should be accomplished. There are several methods that can be used to verify the electrical continuity of the battery. These are not the only possible methods, simply a sampling of some methods:

- One method is to measure that there is current flowing through the battery itself by a simple clamp on milliamp-range ammeter. A battery is always either charging or discharging. Even when a battery is charged, there is still a measurable float charge current that can be detected to verify that there is continuity in the electrical path through the battery.
- A simple test for continuity is to remove the battery charger from service and verify that the battery provides voltage and current to the dc system. However, the behavior of the various dc-supplied equipment in the station should be considered before using this approach.
- Manufacturers of microprocessor-controlled battery chargers have developed methods for their equipment to periodically (or continuously) test for battery continuity. For example, one manufacturer periodically reduces the float voltage on the battery until current from the battery to the dc load can be measured to confirm continuity.
- Applying test current (as in some ohmic testing devices, or devices for locating dc grounds) will provide a current that when measured elsewhere in the string, will prove that the circuit is continuous.
- Internal ohmic measurements of the cells and units of lead-acid batteries (VRLA & VLA) can detect lack of continuity within the cells of a battery string; and when used in conjunction with resistance measurements of the battery's external connections, can prove continuity. Also some methods of taking internal ohmic measurements, by their very nature, can prove the continuity of a battery string without having to use the results of resistance measurements of the external connections.
- Specific gravity tests could infer continuity because without continuity there could be no charging occurring; and if there is no charging, then specific gravity will go down below acceptable levels over time.

No matter how the electrical continuity of a battery set is verified, it is a necessary maintenance activity that must be performed at the intervals prescribed by Table 1-4 to insure that the station dc supply has a path that can provide the required current to the Protection System at all times.

When should I check the station batteries to see if they have sufficient energy to perform as manufactured?

The answer to this question depends on the type of battery (valve-regulated lead-acid, vented lead-acid, or nickel-cadmium) and the maintenance activity chosen.

For example, if you have a valve-regulated lead-acid (VRLA) station battery, and you have chosen to evaluate the measured cell/unit internal ohmic values to the battery cell's baseline, you will have to perform verification at a maximum maintenance interval of no greater than every six months. While this interval might seem to be quite short, keep in mind that the six-

month interval is important for VRLA batteries; this interval provides an accumulation of data that better shows when a VRLA battery is incapable of performing as manufactured.

If, for a VRLA station battery, you choose to conduct a performance capacity test on the entire station battery as the maintenance activity, then you will have to perform verification at a maximum maintenance interval of no greater than every three calendar years.

How is a baseline established for cell/unit internal ohmic measurements?

Establishment of cell/unit internal ohmic baseline measurements should be completed when lead-acid batteries are newly installed. To ensure that the baseline ohmic cell/unit values are most indicative of the station battery's ability to perform as manufactured, they should be made at some point in time after the installation to allow the cell chemistry to stabilize after the initial freshening charge. An accepted industry practice for establishing baseline values is after six-months of installation, with the battery fully charged and in service. However, it is recommended that each owner, when establishing a baseline, should consult the battery manufacturer for specific instructions on establishing an ohmic baseline for their product, if available.

When internal ohmic measurements are taken, the same make/model test equipment should be used to establish the baseline and used for the future trending of the cells internal ohmic measurements because of variances in test equipment and the type of ohmic measurement used by different manufacturer's equipment. Keep in mind that one manufacturer's "Conductance" test equipment does not produce similar results as another manufacturer's "Conductance" test equipment, even though both manufacturers have produced "Ohmic" test equipment. Therefore, for meaningful results to an established baseline, the same make/model of instrument should be used.

For all new installations of valve-regulated lead-acid (VRLA) batteries and vented lead-acid (VLA) batteries, where trending of the cells internal ohmic measurements to a baseline are to be used to determine the ability of the station battery to perform as manufactured, the establishment of the baseline, as described above, should be followed at the time of installation to insure the most accurate trending of the cell/unit. However, often for older VRLA batteries, the owners of the station batteries have not established a baseline at installation. Also for owners of VLA batteries who want to establish a maintenance activity which requires trending of measured ohmic values to a baseline, there was typically no baseline established at installation of the station battery to trend to.

To resolve the problem of the unavailability of baseline internal ohmic measurements for the individual cell/unit of a station battery, many manufacturers of internal ohmic measurement devices have established libraries of baseline values for VRLA and VLA batteries using their testing device. Also, several of the battery manufacturers have libraries of baselines for their products that can be used to trend to. However, it is important that when using battery manufacturer-supplied data that it is verified that the baseline readings to be used were taken with the same ohmic testing device that will be used for future measurements (for example "Conductance Readings" from one manufacturer's test equipment do not correlate to "Impedance Readings" from a different manufacturer's test equipment). Although many manufacturers may have provided baseline values, which will allow trending of the internal ohmic measurements over the remaining life of a station battery, these baselines are not the actual cell/unit measurements for the battery being trended. It is important to have a baseline tailored to the station battery to more accurately use the tool of ohmic measurement trending. That more customized baseline

can only be created by following the establishment of a baseline for each cell/unit at the time of installation of the station battery.

Why determine the State of Charge?

Even though there is no present requirement to check the state of charge of a battery, it can be a very useful tool in determining the overall condition of a battery system. The following discussions are offered as a general reference.

When a battery is fully charged, the battery is available to deliver its existing capacity. As a battery is discharged, its ability to deliver its maximum available capacity is diminished. It is necessary to determine if the state of charge has dropped to an unacceptable level.

What is State of Charge and how can it be determined in a station battery?

The state of charge of a battery refers to the ratio of residual capacity at a given instant to the maximum capacity available from the battery. When a battery is fully charged, the battery is available to deliver its existing capacity. As a battery is discharged, its ability to deliver its maximum available capacity is diminished. Knowing the amount of energy left in a battery compared with the energy it had when it was fully charged gives the user an indication of how much longer a battery will continue to perform before it needs recharging.

For vented lead-acid (VLA) batteries which use accessible liquid electrolyte, a hydrometer can be used to test the specific gravity of each cell as a measure of its state of charge. The hydrometer depends on measuring changes in the weight of the active chemicals. As the battery discharges, the active electrolyte, sulfuric acid, is consumed and the concentration of the sulfuric acid in water is reduced. This, in turn, reduces the specific gravity of the solution in direct proportion to the state of charge. The actual specific gravity of the electrolyte can, therefore, be used as an indication of the state of charge of the battery. Hydrometer readings may not tell the whole story, as it takes a while for the acid to get mixed up in the cells of a VLA battery. If measured right after charging, you might see high specific gravity readings at the top of the cell, even though it is much less at the bottom. Conversely, if taken shortly after adding water to the cell, the specific gravity readings near the top of the cell will be lower than those at the bottom.

Nickel-cadmium batteries, where the specific gravity of the electrolyte does not change during battery charge and discharge, and valve-regulated lead-acid (VRLA) batteries, where the electrolyte is not accessible, cannot have their state of charge determined by specific gravity readings. For these two types of batteries, and for VLA batteries also, where another method besides taking hydrometer readings is desired, the state of charge may be determined by taking voltage and current readings at the battery terminals. The methods employed to obtain accurate readings vary for the different battery types. Manufacturers' information and IEEE guidelines can be consulted for specifics; (see IEEE 1106 Annex B for Nickel Cadmium batteries, IEEE 1188 Annex A for VRLA batteries and IEEE 450 for VLA batteries.

Why determine the Connection Resistance?

High connection resistance can cause abnormal voltage drop or excessive heating during discharge of a station battery. During periods of a high rate of discharge of the station battery, a very high resistance can cause severe damage. The maintenance requirement to verify battery terminal connection resistance in Table 1-4 is established to verify that the integrity of all battery electrical connections is acceptable. This verification includes cell-to-cell (intercell) and external

circuit terminations. Your method of checking for acceptable values of intercell and terminal connection resistance could be by individual readings, or a combination of the two. There are test methods presently that can read post termination resistances and resistance values between external posts. There are also test methods presently available that take a combination reading of the post termination connection resistance plus the intercell resistance value plus the post termination connection resistance value. Either of the two methods, or any other method, that can show if the adequacy of connections at the battery posts is acceptable.

Adequacy of the electrical terminations can be determined by comparing resistance measurements for all connections taken at the time of station battery's installation to the same resistance measurements taken at the maintenance interval chosen, not to exceed the maximum maintenance interval of Table 1-4. Trending of the interval measurements to the baseline measurements will identify any degradation in the battery connections. When the connection resistance values exceed the acceptance criteria for the connection, the connection is typically disassembled, cleaned, reassembled and measurements taken to verify that the measurements are adequate when compared to the baseline readings.

What conditions should be inspected for visible battery cells?

The maintenance requirement to inspect the cell condition of all station battery cells where the cells are visible is a maintenance requirement of Table 1-4. Station batteries are different from any other component in the Protection Station because they are a perishable product due to the electrochemical process which is used to produce dc electrical current and voltage. This inspection is a detailed visual inspection of the cells for abnormalities that occur in the aging process of the cell. In VLA battery visual inspections, some of the things that the inspector is typically looking for on the plates are signs of sulfation of the plates, abnormal colors (which are an indicator of sulfation or possible copper contamination) and abnormal conditions such as cracked grids. The visual inspection could look for symptoms of hydration that would indicate that the battery has been left in a completely discharged state for a prolonged period. Besides looking at the plates for signs of aging, all internal connections, such as the bus bar connection to each plate, and the connections to all posts of the battery need to be visually inspected for abnormalities. In a complete visual inspection for the condition of the cell the cell plates, separators and sediment space of each cell must be looked at for signs of deterioration. An inspection of the station battery's cell condition also includes looking at all terminal posts and cell-to-cell electric connections to ensure they are corrosion free. The case of the battery containing the cell, or cells, must be inspected for cracks and electrolyte leaks through cracks and the post seals.

This maintenance activity cannot be extended beyond the maximum maintenance interval of Table 1-4 by a Performance-Based Maintenance Program (PBM) because of the electrochemical aging process of the station battery, nor can there be any monitoring associated with it because there must be a visual inspection involved in the activity. A remote visual inspection could possibly be done, but its interval must be no greater than the maximum maintenance interval of Table 1-4.

Why is it necessary to verify the battery string can perform as manufactured? I only care that the battery can trip the breaker, which means that the battery can perform as designed. I oversize my batteries so that even if the battery cannot perform as manufactured, it can still trip my breakers.

The fundamental answer to this question revolves around the concept of battery performance "as designed" vs. battery performance "as manufactured." The purpose of the various sections of Table 1-4 of this standard is to establish requirements for the Protection System owner to maintain the batteries, to ensure they will operate the equipment when there is an incident that requires dc power, and ensure the batteries will continue to provide adequate service until at least the next maintenance interval. To meet these goals, the correct battery has to be properly selected to meet the design parameters, and the battery has to deliver the power it was manufactured to provide.

When testing batteries, it may be difficult to determine the original design (i.e., load profile) of the dc system. This standard is not intended as a design document, and requirements relating to design are, therefore, not included.

Where the dc load profile is known, the best way to determine if the system will operate as designed is to conduct a service test on the battery. However, a service test alone might not fully determine if the battery is healthy. A battery with 50% capacity may be able to pass a service test, but the battery would be in a serious state of deterioration and could fail at some point in the near future.

To ensure that the battery will meet the required load profile and continue to meet the load profile until the next maintenance interval, the installed battery must be sized correctly (i.e., a correct design), and it must be in a good state of health. Since the design of the dc system is not within the scope of the standard, the only consistent and reliable method to ensure that the battery is in a good state of health is to confirm that it can perform as manufactured. If the battery can perform as manufactured and it has been designed properly, the system should operate properly until the next maintenance interval.

How do I verify the battery string can perform as manufactured?

Optimally, actual battery performance should be verified against the manufacturer's rating curves. The best practice for evaluating battery performance is via a performance test. However, due to both logistical and system reliability concerns, some Protection System owners prefer other methods to determine if a battery can perform as manufactured. There are several battery parameters that can be evaluated to determine if a battery can perform as manufactured. Ohmic measurements and float current are two examples of parameters that have been reported to assist in determining if a battery string can perform as manufactured.

The evaluation of battery parameters in determining battery health is a complex issue, and is not an exact science. This standard gives the user an opportunity to utilize other measured parameters to determine if the battery can perform as manufactured. It is the responsibility of the Protection System owner, however, to maintain a documented process that demonstrates the chosen parameter(s) and associated methodology used to determine if the battery string can perform as manufactured.

Whatever parameters are used to evaluate the battery (ohmic measurements, float current, float voltages, temperature, specific gravity, performance test, or combination thereof), the goal is to determine the value of the measurement (or the percentage change) at which the battery fails to perform as manufactured, or the point where the battery is deteriorating so rapidly that it will not perform as manufactured before the next maintenance interval.

This necessitates the need for establishing and documenting a baseline. A baseline may be required of every individual cell, a particular battery installation, or a specific make, model, or size of a cell. Given a consistent cell manufacturing process, it may be possible to establish a baseline number for the cell (make/model/type) and, therefore, a subsequent baseline for every installation would not be necessary. However, future installations of the same battery types should be spot-checked to ensure that your baseline remains applicable.

Consistent testing methods by trained personnel are essential. Moreover, it is essential that these technicians utilize the same make/model of ohmic test equipment each time readings are taken in order to establish a meaningful and accurate trend line against the established baseline. The type of probe and its location (post, connector, etc.) for the reading need to be the same for each subsequent test. The room temperature should be recorded with the readings for each test as well. Care should be taken to consider any factors that might lead a trending program to become invalid.

Float current along with other measureable parameters can be used in lieu of or in concert with ohmic measurement testing to measure the ability of a battery to perform as manufactured. The key to using any of these measurement parameters is to establish a baseline and the point where the reading indicates that the battery will not perform as manufactured.

The establishment of a baseline may be different for various types of cells and for different types of installations. In some cases, it may be possible to obtain a baseline number from the battery manufacturer, although it is much more likely that the baseline will have to be established after the installation is complete. To some degree, the battery may still be "forming" after installation; consequently, determining a stable baseline may not be possible until several months after the battery has been in service.

The most important part of this process is to determine the point where the ohmic reading (or other measured parameter(s)) indicates that the battery cannot perform as manufactured. That point could be an absolute number, an absolute change, or a percentage change of an established baseline.

Since there are no universally-accepted repositories of this information, the Protection System owner will have to determine the value/percentage where the battery cannot perform as manufactured (heretofore referred to as a failed cell). This is the most difficult and important part of the entire process.

To determine the point where the battery fails to perform as manufactured, it is helpful to have a history of a battery type, if the data includes the parameter(s) used to evaluate the battery's ability to perform as manufactured against the actual demonstrated performance/capacity of a battery/cell.

For example, when an ohmic reading has been recorded that the user suspects is indicating a failed cell, a performance test of that cell (or string) should be conducted in order to prove/quantify that the cell has failed. Through this process, the user needs to determine the ohmic value at which the performance of the cell has dropped below 80% of the manufactured, rated performance. It is likely that there may be a variation in ohmic readings that indicates a failed cell (possibly significant). It is prudent to use the most conservative values to determine the point at which the cell should be marked for replacement. Periodically, the user should demonstrate that an "adequate" ohmic reading equates to an adequate battery performance (>80% of capacity).

Similarly, acceptance criteria for "good" and "failed" cells should be established for other parameters such as float current, specific gravity, etc., if used to determine the ability of a battery to function as designed.

What happens if I change the make/model of ohmic test equipment after the battery has been installed for a period of time?

If a user decides to switch testers, either voluntarily or because the equipment is not supported/sold any longer, the user may have to establish a new base line and new parameters that indicate when the battery no longer performs as manufactured. The user always has a choice to perform a capacity test in lieu of establishing new parameters.

What are some of the differences between lead-acid and nickel-cadmium batteries?

There is a marked difference in the aging process of lead acid and nickel-cadmium station batteries. The difference in the aging process of these two types of batteries is chiefly due to the electrochemical process of the battery type. Aging and eventual failure of lead acid batteries is due to expansion and corrosion of the positive grid structure, loss of positive plate active material, and loss of capacity caused by physical changes in the active material of the positive plates. In contrast, the primary failure of nickel-cadmium batteries is due to the gradual linear aging of the active materials in the plates. The electrolyte of a nickel-cadmium battery only facilitates the chemical reaction (it functions only to transfer ions between the positive and negative plates), but is not chemically altered during the process like the electrolyte of a lead acid battery. A lead acid battery experiences continued corrosion of the positive plate and grid structure throughout its operational life while a nickel-cadmium battery does not.

Changes to the properties of a lead acid battery when periodically measured and trended to a baseline, can indicate aging of the grid structure, positive plate deterioration, or changes in the active materials in the plate.

Because of the clear differences in the aging process of lead acid and nickel-cadmium batteries, there are no significantly measurable properties of the nickel-cadmium battery that can be measured at a periodic interval and trended to determine aging. For this reason, Table 1-4(c) (Protection System Station dc supply Using nickel-cadmium [NiCad] Batteries) only specifies one minimum maintenance activity and associated maximum maintenance interval necessary to verify that the station battery can perform as manufactured by evaluating cell/unit measurements indicative of battery performance against the station battery baseline. This maintenance activity is to conduct a performance or modified performance capacity test of the entire battery bank.

Why in Table 1-4 of PRC-005-X is there a maintenance activity to inspect the structural intergrity of the battery rack?

The purpose of this inspection is to verify that the battery rack is correctly installed and has no deterioration that could weaken its structural integrity.

Because the battery rack is specifically manufactured for the battery that is mounted on it, weakening of its structural members by rust or corrosion can physically jeopardize the battery.

What is required to comply with the "Unintentional dc Grounds" requirement?

In most cases, the first ground that appears on a battery is not a problem. It is the unintentional ground that appears on the opposite pole that becomes problematic. Even then many systems

are designed to operate favorably under some unintentional DC ground situations. It is up to the owner of the Protection System to determine if corrective actions are needed on detected unintentional DC grounds. The standard merely requires that a check be made for the existence of Unintentional DC Grounds. Obviously, a "check-off" of some sort will have to be devised by the inspecting entity to document that a check is routinely done for Unintentional DC Grounds because of the possible consequences to the Protection System.

Where the standard refers to "all cells," is it sufficient to have a documentation method that refers to "all cells," or do we need to have separate documentation for every cell? For example, do I need 60 individual documented check-offs for good electrolyte level, or would a single check-off per bank be sufficient?

A single check-off per battery bank is sufficient for documentation, as long as the single check-off attests to checking all cells/units.

Does this standard refer to Station batteries or all batteries; for example, Communications Site Batteries?

This standard refers to Station Batteries. The drafting team does not believe that the scope of this standard refers to communications sites. The batteries covered under PRC-005-X are the batteries that supply the trip current to the trip coils of the interrupting devices that are a part of the Protection System. The SDT believes that a loss of power to the communications systems at a remote site would cause the communications systems associated with protective relays to alarm at the substation. At this point, the corrective actions can be initiated.

What are cell/unit internal ohmic measurements?

With the introduction of Valve-Regulated Lead-Acid (VRLA) batteries to station dc supplies in the 1980's several of the standard maintenance tools that are used on Vented Lead-Acid (VLA) batteries were unable to be used on this new type of lead-acid battery to determine its state of health. The only tools that were available to give indication of the health of these new VRLA batteries were voltage readings of the total battery voltage, the voltage of the individual cells and periodic discharge tests.

In the search for a tool for determining the health of a VRLA battery several manufacturers studied the electrical model of a lead acid battery's current path through its cell. The overall battery current path consists of resistance and inductive and capacitive reactance. The inductive reactance in the current path through the battery is so minuscule when compared to the huge capacitive reactance of the cells that it is often ignored in most circuit models of the battery cell. Taking the basic model of a battery cell manufacturers of battery test equipment have developed and marketed testing devices to take measurements of the current path to detect degradation in the internal path through the cell.

In the battery industry, these various types of measurements are referred to as ohmic measurements. Terms used by the industry to describe ohmic measurements are ac conductance, ac impedance, and dc resistance. They are defined by the test equipment providers and IEEE and refer to the method of taking ohmic measurements of a lead acid battery. For example, in one manufacturer's ac conductance equipment measurements are taken by applying a voltage of a known frequency and amplitude across a cell or battery unit and observing the ac current flow it produces in response to the voltage. A manufacturer of an ac impedance meter measures ac current of a known frequency and amplitude that is passed through the whole battery string and determines the impedances of each cell or unit by measuring the resultant ac

voltage drop across them. On the other hand, dc resistance of a cell is measured by a third manufacturer's equipment by applying a dc load across the cell or unit and measuring the step change in both the voltage and current to calculate the internal dc resistance of the cell or unit.

It is important to note that because of the rapid development of the market for ohmic measurement devices, there were no standards developed or used to mandate the test signals used in making ohmic measurements. Manufacturers using proprietary methods and applying different frequencies and magnitudes for their signals have developed a diversity of measurement devices. This diversity in test signals coupled with the three different types of ohmic measurements techniques (impedance conductance and resistance) make it impossible to always get the same ohmic measurement for a cell with different ohmic measurement devices. However, IEEE has recognized the great value for choosing one device for ohmic measurement, no matter who makes it or the method to calculate the ohmic measurement. The only caution given by IEEE and the battery manufacturers is that when trending the cells of a lead acid station battery consistent ohmic measurement devices should be used to establish the baseline measurement and to trend the battery set for its entire life.

For VRLA batteries both IEEE Standard 1188 (Maintenance, Testing and Replacement of VRLA Batteries) and IEEE Standard 1187 (Installation Design and Installation of VRLA Batteries) recognize the importance of the maintenance activity of establishing a baseline for "cell/unit internal ohmic measurements (impedance, conductance and resistance)" and trending them at frequent intervals over the life of the battery. There are extensive discussions about the need for taking these measurements in these standards. IEEE Standard 1188 requires taking internal ohmic values as described in Annex C4 during regular inspections of the station battery. For VRLA batteries IEEE Standard 1188 in talking about the necessity of establishing a baseline and trending it over time says, "…depending on the degree of change a performance test, cell replacement or other corrective action may be necessary…" (IEEE std 1188-2005, C.4 page 18).

For VLA batteries IEEE Standard 484 (Installation of VLA batteries) gives several guidelines about establishing baseline measurements on newly installed lead acid stationary batteries. The standard also discusses the need to look for significant changes in the ohmic measurements, the caution that measurement data will differ with each type of model of instrument used, and lists a number of factors that affect ohmic measurements.

At the beginning of the 21st century, EPRI conducted a series of extensive studies to determine the relationship of internal ohmic measurements to the capacity of a lead acid battery cell. The studies indicated that internal ohmic measurements were in fact a good indicator of a lead acid battery cell's capacity, but because users often were only interested in the total station battery capacity and the technology does not precisely predict overall battery capacity, if a user only needs "an accurate measure of the overall battery capacity," they should "perform a battery capacity test."

Prior to the EPRI studies some large and small companies which owned and maintained station dc supplies in NERC Protection Systems developed maintenance programs where trending of ohmic measurements of cells/units of the station's battery became the maintenance activity for determining if the station battery could perform as manufactured. By evaluation of the trending of the ohmic measurements over time, the owner could track the performance of the individual components of the station battery and determine if a total station battery or components of it

required capacity testing, removal, replacement or in many instances replacement of the entire station battery. By taking this condition based approach these owners have eliminated having to perform capacity testing at prescribed intervals to determine if a battery needs to be replaced and are still able to effectively determine if a station battery can perform as manufactured.

My VRLA batteries have multiple-cells within an individual battery jar (or unit); how am I expected to comply with the cell-to-cell ohmic measurement requirements on these units that I cannot get to?

Measurement of cell/unit (not all batteries allow access to "individual cells" some "units" or jars may have multiple cells within a jar) internal ohmic values of all types of lead acid batteries where the cells of the battery are not visible is a station dc supply maintenance activity in Table 1-4. In cases where individual cells in a multi-cell unit are inaccessible, an ohmic measurement of the entire unit may be made.

I have a concern about my batteries being used to support additional auxiliary loads beyond my protection control systems in a generation station. Is ohmic measurement testing sufficient for my needs?

While this standard is focused on addressing requirements for Protection Systems, if batteries are used to service other load requirements beyond that of Protection Systems (e.g. pumps, valves, inverter loads), the functional entity may consider additional testing to confirm that the capacity of the battery is sufficient to support all loads.

Why verify voltage?

There are two required maintenance activities associated with verification of dc voltages in Table 1-4. These two required activities are to verify station dc supply voltage and float voltage of the battery charger, and have different maximum maintenance intervals. Both of these voltage verification requirements relate directly to the battery charger maintenance.

The verification of the dc supply voltage is simply an observation of battery voltage to prove that the charger has not been lost or is not malfunctioning; a reading taken from the battery charger panel meter or even SCADA values of the dc voltage could be some of the ways that one could satisfy the requirements. Low battery voltage below float voltage indicates that the battery may be on discharge and, if not corrected, the station battery could discharge down to some extremely low value that will not operate the Protection System. High voltage, close to or above the maximum allowable dc voltage for equipment connected to the station dc supply indicates the battery charger may be malfunctioning by producing high dc voltage levels on the Protection System. If corrective actions are not taken to bring the high voltage down, the dc power supplies and other electronic devices connected to the station dc supply may be damaged. The maintenance activity of verifying the float voltage of the battery charger is not to prove that a charger is lost or producing high voltages on the station dc supply, but rather to prove that the charger is properly floating the battery within the proper voltage limits. As above, there are many ways that this requirement can be met.

Why check for the electrolyte level?

In vented lead-acid (VLA) and nickel-cadmium (NiCad) batteries the visible electrolyte level must be checked as one of the required maintenance activities that must be performed at an interval that is equal to or less than the maximum maintenance interval of Table 1-4. Because the electrolyte level in valve-regulated lead-acid (VRLA) batteries cannot be observed, there is no maintenance activity listed in Table 1-4 of the standard for checking the electrolyte level. Low

electrolyte level of any cell of a VLA or NiCad station battery is a condition requiring correction. Typically, the electrolyte level should be returned to an acceptable level for both types of batteries (VLA and NiCad) by adding distilled or other approved-quality water to the cell.

Often people confuse the interval for watering all cells required due to evaporation of the electrolyte in the station battery cells with the maximum maintenance interval required to check the electrolyte level. In many of the modern station batteries, the jar containing the electrolyte is so large with the band between the high and low electrolyte level so wide that normal evaporation which would require periodic watering of all cells takes several years to occur. However, because loss of electrolyte due to cracks in the jar, overcharging of the station battery, or other unforeseen events can cause rapid loss of electrolyte; the shorter maximum maintenance intervals for checking the electrolyte level are required. A low level of electrolyte in a VLA battery cell which exposes the tops of the plates can cause the exposed portion of the plates to accelerated sulfation resulting in loss of cell capacity. Also, in a VLA battery where the electrolyte level goes below the end of the cell withdrawal tube or filling funnel, gasses can exit the cell by the tube instead of the flame arrester and present an explosion hazard.

What are the parameters that can be evaluated in Tables 1-4(a) and 1-4(b)?

The most common parameter that is periodically trended and evaluated by industry today to verify that the station battery can perform as manufactured is internal ohmic cell/unit measurements.

In the mid-1990s, several large and small utilities began developing maintenance and testing programs for Protection System station batteries using a condition based maintenance approach of trending internal ohmic measurements to each station battery cell's baseline value. Battery owners use the data collected from this maintenance activity to determine (1) when a station battery requires a capacity test (instead of performing a capacity test on a predetermined, prescribed interval), (2) when an individual cell or battery unit should be replaced, or (3) based on the analysis of the trended data, if the station battery should be replaced without performing a capacity test.

Other examples of measurable parameters that can be periodically trended and evaluated for lead acid batteries are cell voltage, float current, connection resistance. However, periodically trending and evaluating cell/unit Ohmic measurements are the most common battery/cell parameters that are evaluated by industry to verify a lead acid battery string can perform as manufactured.

Why does it appear that there are two maintenance activities in Table 1-4(b) (for VRLA batteries) that appear to be the same activity and have the same maximum maintenance interval?

There are two different and distinct reasons for doing almost the same maintenance activity at the same interval for valve-regulated lead-acid (VRLA) batteries. The first similar activity for VRLA batteries (Table 1-4(b)) that has the same maximum maintenance interval is to "measure battery cell/unit internal ohmic values." Part of the reason for this activity is because the visual inspection of the cell condition is unavailable for VRLA batteries. Besides the requirement to measure the internal ohmic measurements of VRLA batteries to determine the internal health of the cell, the maximum maintenance interval for this activity is significantly shorter than the interval for vented lead-acid (VLA) due to some unique failure modes for VRLA batteries. Some

of the potential problems that VRLA batteries are susceptible to that do not affect VLA batteries are thermal runaway, cell dry-out, and cell reversal when one cell has a very low capacity.

The other similar activity listed in Table 1-4(b) is "…verify that the station battery can perform as manufactured by evaluating the measured cell/unit measurements indicative of battery performance (e.g. internal ohmic values) against the station battery baseline." This activity allows an owner the option to choose between this activity with its much shorter maximum maintenance interval or the longer maximum maintenance interval for the maintenance activity to "Verify that the station battery can perform as manufactured by conducting a performance or modified performance capacity test of the entire battery bank."

For VRLA batteries, there are two drivers for internal ohmic readings. The first driver is for a means to trend battery life. Trending against the baseline of VRLA cells in a battery string is essential to determine the approximate state of health of the battery. Ohmic measurement testing may be used as the mechanism for measuring the battery cells. If all the cells in the string exhibit a consistent trend line and that trend line has not risen above a specific deviation (e.g. 30%) over baseline for impedance tests or below baseline for conductance tests, then a judgment can be made that the battery is still in a reasonably good state of health and able to 'perform as manufactured.' It is essential that the specific deviation mentioned above is based on data (test or otherwise) that correlates the ohmic readings for a specific battery/tester combination to the health of the battery. This is the intent of the "perform **as** manufactured six-month test" at Row 4 on Table 1-4b.

The second big driver is VRLA batteries tendency for thermal runaway. This is the intent of the "thermal runaway test" at Row 2 on Table 1-4b. In order to detect a cell in thermal runaway, you need not necessarily have a formal trending program. When a single cell/unit changes significantly or significantly varies from the other cells (e.g. a doubling of resistance/impedance or a 50% decrease in conductance), there is a high probability that the cell/unit/string needs to be replaced as soon as possible. In other words, if the battery is 10 years old and all the cells have approached a significant change in ohmic values over baseline, then you have a battery which is approaching end of life. You need to get ready to buy a new battery, but you do not have to worry about an impending catastrophic failure. On the other hand, if the battery is five years old and you have one cell that has a markedly different ohmic reading than all the other cells, then you need to be worried that this cell is susceptible to thermal runaway. If the float (charging) current has risen significantly and the ohmic measurement has increased/decreased as described above then concern of catastrophic failure should trigger attention for corrective action.

If an entity elects to use a capacity test rather than a cell ohmic value trending program, this does not eliminate the need to be concerned about thermal runaway – the entity still needs to do the six-month readings and look for cells which are outliers in the string but they need not trend results against the factory/as new baseline. Some entities will not mind the extra administrative burden of having the ongoing trending program against baseline - others would rather just do the capacity test and not have to trend the data against baseline. Nonetheless, all entities must look for ohmic outliers on a six-month basis.

It is possible to accomplish both tasks listed (trend testing for capability and testing for thermal runaway candidates) with the very same ohmic test. It becomes an analysis exercise of watching the trend from baselines and watching for the oblique cell measurement.

In table 1-4(f) (Exclusions for Protection System Station dc Supply Monitoring Devices and Systems), must all component attributes listed in the table be met before an exclusion can be granted for a maintenance activity?

Table 1-4(f) was created by the drafting team to allow Protection System dc supply owners to obtain exclusions from periodic maintenance activities by using monitoring devices. The basis of the exclusions granted in the table is that the monitoring devices must incorporate the monitoring capability of microprocessor based components which perform continuous self-monitoring. For failure of the microprocessor device used in dc supply monitoring, the self-checking routine in the microprocessor must generate an alarm which will be reported within 24 hours of device failure to a location where corrective action can be initiated.

Table 1-4(f) lists 8 component attributes along with a specific periodic maintenance activity associated with each of the 8 attributes listed. If an owner of a station dc supply wants to be excluded from periodically performing one of the 8 maintenance activities listed in table 1-4(f), the owner must have evidence that the monitoring and alarming component attributes associated with the excluded maintenance activity are met by the self-checking microprocessor based device with the specific component attribute listed in the table 1-4(f).

For example if an owner of a VLA station battery does not want to "verify station dc supply voltage" every "4 calendar months" (see table 1-4(a)), the owner can install a monitoring and alarming device "with high and low voltage monitoring and alarming of the battery charger voltage to detect charger overvoltage and charger failure" and "no periodic verification of station dc supply voltage is required" (see table 1-4(f) first row). However, if for the same Protection System discussed above, the owner does not install "electrolyte level monitoring and alarming in every cell" and "unintentional dc ground monitoring and alarming" (see second and third rows of table 1-4(f)), the owner will have to "inspect electrolyte level and for unintentional grounds" every "4 calendar months" (see table 1-4(a)).

15.5 Associated communications equipment (Table 1-2)

The equipment used for tripping in a communications-assisted trip scheme is a vital piece of the trip circuit. Remote action causing a local trip can be thought of as another parallel trip path to the trip coil that must be tested. Besides the trip output and wiring to the trip coil(s), there is also a communications medium that must be maintained. Newer technologies now exist that achieve communications-assisted tripping without the conventional wiring practices of older technology. For example, older technologies may have included Frequency Shift Key methods. This technology requires that guard and trip levels be maintained. The actual tripping path(s) to the trip coil(s) may be tested as a parallel trip path within the dc control circuitry tests. Emerging technologies transfer digital information over a variety of carrier mediums that are then interpreted locally as trip signals. The requirements apply to the communicated signal needed for the proper operation of the protective relay trip logic or scheme. Therefore, this standard is applied to equipment used to convey both trip signals (permissive or direct) and block signals.

It was the intent of this standard to require that a test be performed on any communications-assisted trip scheme, regardless of the vintage of technology. The essential element is that the tripping (or blocking) occurs locally when the remote action has been asserted; or that the tripping (or blocking) occurs remotely when the local action is asserted. Note that the required testing can still be done within the concept of testing by overlapping segments. Associated communications equipment can be (but is not limited to) testing at other times and different frequencies as the protective relays, the individual trip paths and the affected circuit interrupting devices.

Some newer installations utilize digital signals over fiber-optics from the protective relays in the control house to the circuit interrupting device in the yard. This method of tripping the circuit breaker, even though it might be considered communications, must be maintained per the dc control circuitry maintenance requirements.

15.5.1 Frequently Asked Questions:

What are some examples of mechanisms to check communications equipment functioning?

For unmonitored Protection Systems, various types of communications systems will have different facilities for on-site integrity checking to be performed at least every four months during a substation visit. Some examples are, but not limited to:

- On-off power-line carrier systems can be checked by performing a manual carrier keying test between the line terminals, or carrier check-back test from one terminal.
- Systems which use frequency-shift communications with a continuous guard signal (over a telephone circuit, analog microwave system, etc.) can be checked by observing for a loss-of-guard indication or alarm. For frequency-shift power-line carrier systems, the guard signal level meter can also be checked.
- Hard-wired pilot wire line Protection Systems typically have pilot-wire monitoring relays that give an alarm indication for a pilot wire ground or open pilot wire circuit loop.
- Digital communications systems typically have a data reception indicator or data error indicator (based on loss of signal, bit error rate, or frame error checking).

For monitored Protection Systems, various types of communications systems will have different facilities for monitoring the presence of the communications channel, and activating alarms that can be monitored remotely. Some examples are, but not limited to:

- On-off power-line carrier systems can be shown to be operational by automated periodic power-line carrier check-back tests with remote alarming of failures.
- Systems which use a frequency-shift communications with a continuous guard signal (over a telephone circuit, analog microwave system, etc.) can be remotely monitored with a loss-of-guard alarm or low signal level alarm.
- Hard-wired pilot wire line Protection Systems can be monitored by remote alarming of pilot-wire monitoring relays.
- Digital communications systems can activate remotely monitored alarms for data reception loss or data error indications.
- Systems can be queried for the data error rates.

For the highest degree of monitoring of Protection Systems, the communications system must monitor all aspects of the performance and quality of the channel that show it meets the design performance criteria, including monitoring of the channel interface to protective relays.

- In many communications systems signal quality measurements, including signal-to-noise ratio, received signal level, reflected transmitter power or standing wave ratio, propagation delay, and data error rates are compared to alarm limits. These alarms are connected for remote monitoring.
- Alarms for inadequate performance are remotely monitored at all times, and the alarm communications system to the remote monitoring site must itself be continuously

monitored to assure that the actual alarm status at the communications equipment location is continuously being reflected at the remote monitoring site.

What is needed for the four-month inspection of communications-assisted trip scheme equipment?

The four-month inspection applies to unmonitored equipment. An example of compliance with this requirement might be, but is not limited to:

With each site visit, check that the equipment is free from alarms; check any metered signal levels, and that power is still applied. While this might be explicit for a particular type of equipment (i.e., FSK equipment), the concept should be that the entity verify that the communications equipment that is used in a Protection System is operable through a cursory inspection and site visit. This site visit can be eliminated on this particular example if the FSK equipment had a monitored alarm on Loss of Guard. Blocking carrier systems with auto checkbacks will present an alarm when the channel fails allowing a visual indication. With no auto checkback, the channel integrity will need to be verified by a manual checkback or a two ended signal check. This check could also be eliminated by bring the auto checkback failure alarm to the monitored central location.

Does a fiber optic I/O scheme used for breaker tripping or control within a station, for example - transmitting a trip signal or control logic between the control house and the breaker control cabinet, constitute a communications system?

This equipment is presently classified as being part of the Protection System control circuitry and tested per the portions of Table 1 applicable to “Protection System Control Circuitry”, rather than those portions of the table applicable to communications equipment.

What is meant by “Channel” and “Communications Systems” in Table 1-2?

The transmission of logic or data from a relay in one station to a relay in another station for use in a pilot relay scheme will require a communications system of some sort. Typical relay communications systems use fiber optics, leased audio channels, power line carrier, and microwave. The overall communications system includes the channel and the associated communications equipment.

This standard refers to the “channel” as the medium between the transmitters and receivers in the relay panels such as a leased audio or digital communications circuit, power line and power line carrier auxiliary equipment, and fiber. The dividing line between the channel and the associated communications equipment is different for each type of media.

Examples of the Channel:

- Power Line Carrier (PLC) - The PLC channel starts and ends at the PLC transmitter and receiver output unless there is an internal hybrid. The channel includes the external hybrids, tuners, wave traps and the power line itself.
- Microwave –The channel includes the microwave multiplexers, radios, antennae and associated auxiliary equipment. The audio tone and digital transmitters and receivers in the relay panel are the associated communications equipment.
- Digital/Audio Circuit – The channel includes the equipment within and between the substations. The associated communications equipment includes the relay panel transmitters and receivers and the interface equipment in the relays.

- Fiber Optic – The channel starts at the fiber optic connectors on the fiber distribution panel at the local station and goes to the fiber optic distribution panel at the remote substation. The jumpers that connect the relaying equipment to the fiber distribution panel and any optical-electrical signal format converters are the associated communications equipment

Figure 1-2, A-1 and A-2 at the end of this document show good examples of the communications channel and the associated communications equipment.

In Table 1-2, the Maintenance Activities section of the Protection System Communications Equipment and Channels refers to the quality of the channel meeting "performance criteria." What is meant by performance criteria?

Protection System communications channels must have a means of determining if the channel and communications equipment is operating normally. If the channel is not operating normally, an alarm will be indicated. For unmonitored systems, this alarm will probably be on the panel. For monitored systems, the alarm will be transmitted to a remote location.

Each entity will have established a nominal performance level for each Protection System communications channel that is consistent with proper functioning of the Protection System. If that level of nominal performance is not being met, the system will go into alarm. Following are some examples of Protection System communications channel performance measuring:

- For direct transfer trip using a frequency shift power line carrier channel, a guard level monitor is part of the equipment. A normal receive level is established when the system is calibrated and if the signal level drops below an established level, the system will indicate an alarm.
- An on-off blocking signal over power line carrier is used for directional comparison blocking schemes on transmission lines. During a Fault, block logic is sent to the remote relays by turning on a local transmitter and sending the signal over the power line to a receiver at the remote end. This signal is normally off so continuous levels cannot be checked. These schemes use check-back testing to determine channel performance. A predetermined signal sequence is sent to the remote end and the remote end decodes this signal and sends a signal sequence back. If the sending end receives the correct information from the remote terminal, the test passes and no alarm is indicated. Full power and reduced power tests are typically run. Power levels for these tests are determined at the time of calibration.
- Pilot wire relay systems use a hardwire communications circuit to communicate between the local and remote ends of the protective zone. This circuit is monitored by circulating a dc current between the relay systems. A typical level may be 1 mA. If the level drops below the setting of the alarm monitor, the system will indicate an alarm.
- Modern digital relay systems use data communications to transmit relay information to the remote end relays. An example of this is a line current differential scheme commonly used on transmission lines. The protective relays communicate current magnitude and phase information over the communications path to determine if the Fault is located in

the protective zone. Quantities such as digital packet loss, bit error rate and channel delay are monitored to determine the quality of the channel. These limits are determined and set during relay commissioning. Once set, any channel quality problems that fall outside the set levels will indicate an alarm.

The previous examples show how some protective relay communications channels can be monitored and how the channel performance can be compared to performance criteria established by the entity. This standard does not state what the performance criteria will be; it just requires that the entity establish nominal criteria so Protection System channel monitoring can be performed.

How is the performance criteria of Protection System communications equipment involved in the maintenance program?

An entity determines the acceptable performance criteria, depending on the technology implemented. If the communications channel performance of a Protection System varies from the pre-determined performance criteria for that system, then these results should be investigated and resolved.

How do I verify the A/D converters of microprocessor-based relays?

There are a variety of ways to do this. Two examples would be: using values gathered via data communications and automatically comparing these values with values from other sources, or using groupings of other measurements (such as vector summation of bus feeder currents) for comparison. Many other methods are possible.

15.6 Alarms (Table 2)

In addition to the tables of maintenance for the components of a Protection System, there is an additional table added for alarms. This additional table was added for clarity. This enabled the common alarm attributes to be consolidated into a single spot, and, thus, make it easier to read the Tables 1-1 through 1-5, Table 3, and Table 4. The alarms need to arrive at a site wherein a corrective action can be initiated. This could be a control room, operations center, etc. The alarming mechanism can be a standard alarming system or an auto-polling system; the only requirement is that the alarm be brought to the action-site within 24 hours. This effectively makes manned-stations equivalent to monitored stations. The alarm of a monitored point (for example a monitored trip path with a lamp) in a manned-station now makes that monitored point eligible for monitored status. Obviously, these same rules apply to a non-manned-station, which is that if the monitored point has an alarm that is auto-reported to the operations center (for example) within 24 hours, then it too is considered monitored.

15.6.1 Frequently Asked Questions:

Why are there activities defined for varying degrees of monitoring a Protection System component when that level of technology may not yet be available?

There may already be some equipment available that is capable of meeting the highest levels of monitoring criteria listed in the Tables. However, even if there is no equipment available today that can meet this level of monitoring the standard establishes the necessary requirements for when such equipment becomes available. By creating a roadmap for development, this provision makes the standard technology neutral. The Standard Drafting Team wants to avoid the need to revise the standard in a few years to accommodate technology advances that may be coming to the industry.

Does a fail-safe "form b" contact that is alarmed to a 24/7 operation center classify as an alarm path with monitoring?

If the fail-safe "form-b" contact that is alarmed to a 24/7 operation center causes the alarm to activate for failure of any portion of the alarming path from the alarm origin to the 24/7 operations center, then this can be classified as an alarm path with monitoring.

15.7 Distributed UFLS and Distributed UVLS Systems (Table 3)

Distributed UFLS and distributed UVLS systems have their maintenance activities documented in Table 3 due to their distributed nature allowing reduced maintenance activities and extended maximum maintenance intervals. Relays have the same maintenance activities and intervals as Table 1-1. Voltage and current-sensing devices have the same maintenance activity and interval as Table 1-3. DC systems need only have their voltage read at the relay every 12 years. Control circuits have the following maintenance activities every 12 years:

- Verify the trip path between the relay and lock-out and/or auxiliary tripping device(s).
- Verify operation of any lock-out and/or auxiliary tripping device(s) used in the trip circuit.
- No verification of trip path required between the lock-out (and/or auxiliary tripping device) and the non-BES interrupting device.
- No verification of trip path required between the relay and trip coil for circuits that have no lock-out and/or auxiliary tripping device(s).
- No verification of trip coil required.

No maintenance activity is required for associated communication systems for distributed UFLS and distributed UVLS schemes.

Non-BES interrupting devices that participate in a distributed UFLS or distributed UVLS scheme are excluded from the tripping requirement, and part of the control circuit test requirement; however, the part of the trip path control circuitry between the Load-Shed relay and lock-out or auxiliary tripping relay must be tested at least once every 12 years. In the case where there is no lock-out or auxiliary tripping relay used in a distributed UFLS or UVLS scheme which is not part of the BES, there is no control circuit test requirement. There are many circuit interrupting devices in the distribution system that will be operating for any given under-frequency event that requires tripping for that event. A failure in the tripping action of a single distributed system circuit breaker (or non-BES equipment interruption device) will be far less significant than, for example, any single transmission Protection System failure, such as a failure of a bus differential lock-out relay. While many failures of these distributed system circuit breakers (or non-BES equipment interruption device) could add up to be significant, it is also believed that many circuit breakers are operated often on just Fault clearing duty; and, therefore, these circuit breakers are operated at least as frequently as any requirements that appear in this standard.

There are times when a Protection System component will be used on a BES device, as well as a non-BES device, such as a battery bank that serves both a BES circuit breaker and a non-BES interrupting device used for UFLS. In such a case, the battery bank (or other Protection System component) will be subject to the Tables of the standard because it is used for the BES.

15.7.1 Frequently Asked Questions:

The standard reaches further into the distribution system than we would like for UFLS and UVLS

While UFLS and UVLS equipment are located on the distribution network, their job is to protect the Bulk Electric System. This is not beyond the scope of NERC's 215 authority.

FPA section 215(a) definitions section defines bulk power system as: "(A) facilities and control Systems necessary for operating an interconnected electric energy transmission network (or any portion thereof)." That definition, then, is limited by a later statement which adds the term bulk power system "…does not include facilities used in the local distribution of electric energy." Also, Section 215 also covers users, owners, and operators of bulk power Facilities.

UFLS and UVLS (when the UVLS is installed to prevent system voltage collapse or voltage instability for BES reliability) are not "used in the local distribution of electric energy," despite their location on local distribution networks. Further, if UFLS/UVLS Facilities were not covered by the reliability standards, then in order to protect the integrity of the BES during under-frequency or under-voltage events, that Load would have to be shed at the Transmission bus to ensure the Load-generation balance and voltage stability is maintained on the BES.

15.8 Automatic Reclosing (Table 4)

Please see the document referenced in Section F of PRC-005-3, "Considerations for Maintenance and Testing of Autoreclosing Schemes — November 2012", for a discussion of Automatic Reclosing as addressed in PRC-005-3.

15.8.1 Frequently-asked Questions

Automatic Reclosing is a control, not a protective function; why then is Automatic Reclosing maintenance included in the Protection System Maintenance Program (PSMP)?

Automatic Reclosing is a control function. The standard's title 'Protection System and Automatic Reclosing Maintenance' clearly distinguishes (separates) the Automatic Reclosing from the Protection System. Automatic Reclosing is included in the PSMP because it is a more pragmatic approach as compared to creating a parallel and essentially identical 'Control System Maintenance Program' for the two Automatic Reclosing component types.

Our maintenance practice consists of initiating the Automatic Reclosing relay and confirming the breaker closes properly and the close signal is released. This practice verifies the control circuitry associated with Automatic Reclosing. Do you agree?"

The described task partially verifies the control circuit maintenance activity. To meet the control circuit maintenance activity, responsible entities need to verify, *upon initiation*, that the reclosing relay does not issue a *premature closing command*. As noted on page 12 of the SAMS/SPCS report, the concern being addressed within the standard is premature autoreclosing that has the potential to cause generating unit or plant instability. Reclosing applications have many variations, responsible entities will need to verify the applicability of associated supervision/conditional logic and the reclosing relay operation; then verify the conditional logic or that the reclosing relay performs in a manner that does not result in a *premature closing command* being issued.

Some examples of conditions which can result in a premature closing command are: an improper supervision or conditional logic input which provides a false state and allows the reclosing relay to issue an improper close command based on incorrect conditions (i.e. voltage supervision, equipment status, sync window verification); timers utilized for closing actuation or reclosing arming/disarming circuitry which could allow the reclosing relay to issue an improper close command; a reclosing relay output contact failure which could result in a made-up-close condition / failure-to-release condition.

Why was a close-in three phase fault present for twice the normal clearing time chosen for the Automatic Reclosing exclusion? It exceeds TPL requirements and ignores the breaker closing time in a trip-close-trip sequence, thus making the exclusion harder to attain.

This condition represents a situation where a close signal is issued with no time delay or with less time delay than is intended, such as if a reclosing contact is welded closed. This failure mode can result in a minimum trip-close-trip sequence with the two faults cleared in primary protection operating time, and the open time between faults equal to the breaker closing cycle time. The sequence for this failure mode results in system impact equivalent to a high-speed autoreclosing sequence with no delay added in the autoreclosing logic. It represents a failure mode which must be avoided because it exceeds TPL requirements.

Do we have to test the various breaker closing circuit interlocks and controls such as anti-pump?

These components are not specifically addressed within Table 4, and need not be individually tested. They are indirectly verified by performing the Automatic Reclosing control circuitry verification as established in Table 4.

For Automatic Reclosing that <u>is not</u> part of an SPS, do we have to close the circuit breaker periodically?

No. For this application, you need only to verify that the Automatic Reclosing, upon initiation, does not issue a premature closing command. This activity is concerned only with assuring that a premature close does not occur, and cause generating plant instability.

For Automatic Reclosing that <u>is</u> part of an SPS, do we have to close the circuit breaker periodically?

Yes. In this application, successful closing is a necessary portion of the SPS, and must be verified.

15.9 Sudden Pressure Relaying (Table 5)

Please see the document referenced in Section F of PRC-005-X, “Sudden Pressure Relays and Other Devices that Respond to Non-Electrical Quantities – December 2013”, for a discussion of Sudden Pressure Relaying as addressed in PRC-005-X.

15.9.1 Frequently Asked Questions:

How do I verify the pressure or flow sensing mechanism is operable?

Operate, or cause to operate the mechanism responding to the rapid-pressure rise. The standard does not specify how to perform the maintenance.

Why do I have to test the fault pressure relay every 6 years? Our experience is that these devices have no trouble operating as we have had our share of nuisance trips on through-faults.

The frequency of the testing is set to align with previously set maintenance intervals in PRC-005 and align with a survey of respondents as detailed in the previously noted NERC SPCS paper responding to FERC Order 758.

Sudden Pressure Relaying control circuitry is now specifically mentioned in the maintenance tables. Do we have to trip our circuit breaker specifically from the trip output of the sudden pressure relay?

No. Verification may be by breaker tripping, but may be verified in overlapping segments with the Protection System control circuitry.

Can we use Performance Based Maintenance for fault pressure relays?

Yes. Performance Based Maintenance is applicable to fault pressure relays.

15.10 Examples of Evidence of Compliance

To comply with the requirements of this standard, an entity will have to document and save evidence. The evidence can be of many different forms. The Standard Drafting Team recognizes that there are concurrent evidence requirements of other NERC standards that could, at times, fulfill evidence requirements of this standard.

15.10.1 Frequently Asked Questions:

What forms of evidence are acceptable?

Acceptable forms of evidence, as relevant for the requirement being documented include, but are not limited to:

- Process documents or plans
- Data (such as relay settings sheets, photos, SCADA, and test records)
- Database lists, records and/or screen shots that demonstrate compliance information
- Prints, diagrams and/or schematics
- Maintenance records
- Logs (operator, substation, and other types of log)
- Inspection forms
- Mail, memos, or email proving the required information was exchanged, coordinated, submitted or received
- Check-off forms (paper or electronic)
- Any record that demonstrates that the maintenance activity was known, accounted for, and/or performed.

If I replace a failed Protection System component with another component, what testing do I need to perform on the new component?

In order to reset the Table 1 maintenance interval for the replacement component, all relevant Table 1 activities for the component should be performed.

I have evidence to show compliance for PRC-016 ("Special Protection System Misoperation"). Can I also use it to show compliance for this Standard, PRC-005-X?

Maintaining evidence for operation of Special Protection Systems could concurrently be utilized as proof of the operation of the associated trip coil (provided one can be certain of the trip coil involved). Thus, the reporting requirements that one may have to do for the Misoperation of a Special Protection Scheme under PRC-016 could work for the activity tracking requirements under this PRC-005-X.

I maintain Disturbance records which show Protection System operations. Can I use these records to show compliance?

These records can be concurrently utilized as dc trip path verifications, to the degree that they demonstrate the proper function of that dc trip path.

I maintain test reports on some of my Protection System components. Can I use these test reports to show that I have verified a maintenance activity?

Yes.

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18. "Statistical Analysis for Business Decisions" Peters, Summers, 1968

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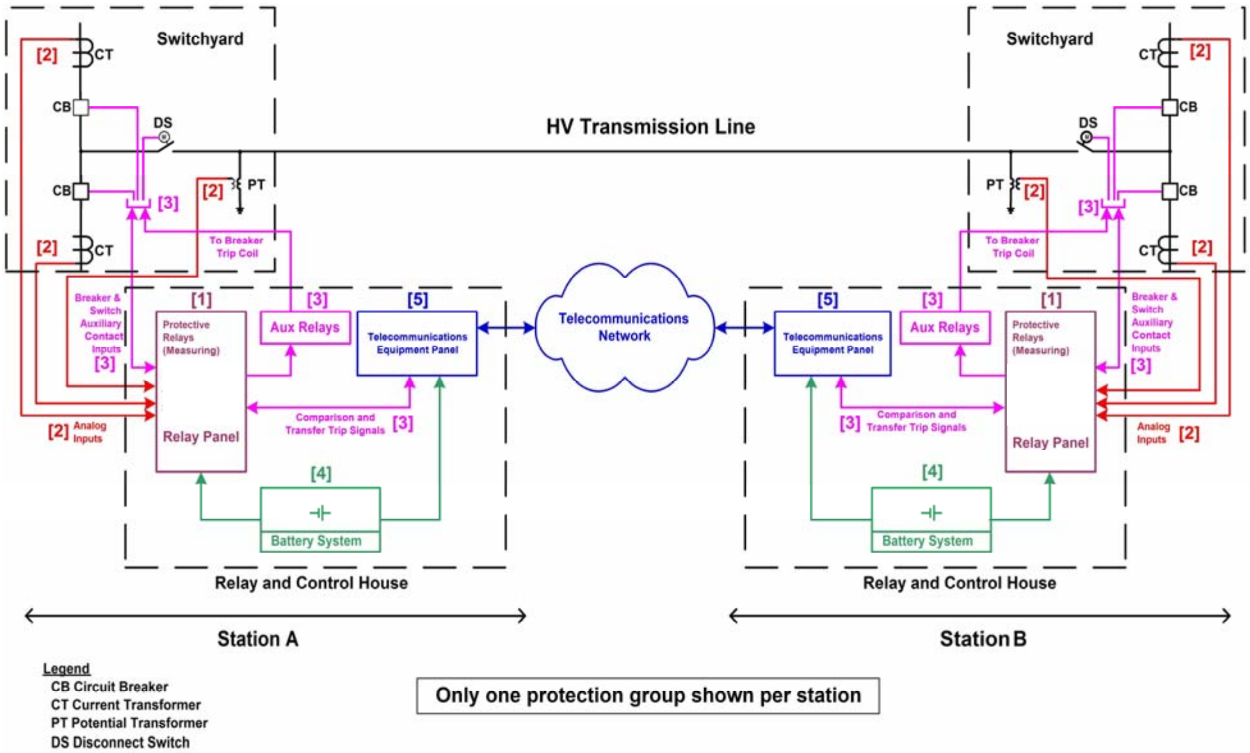
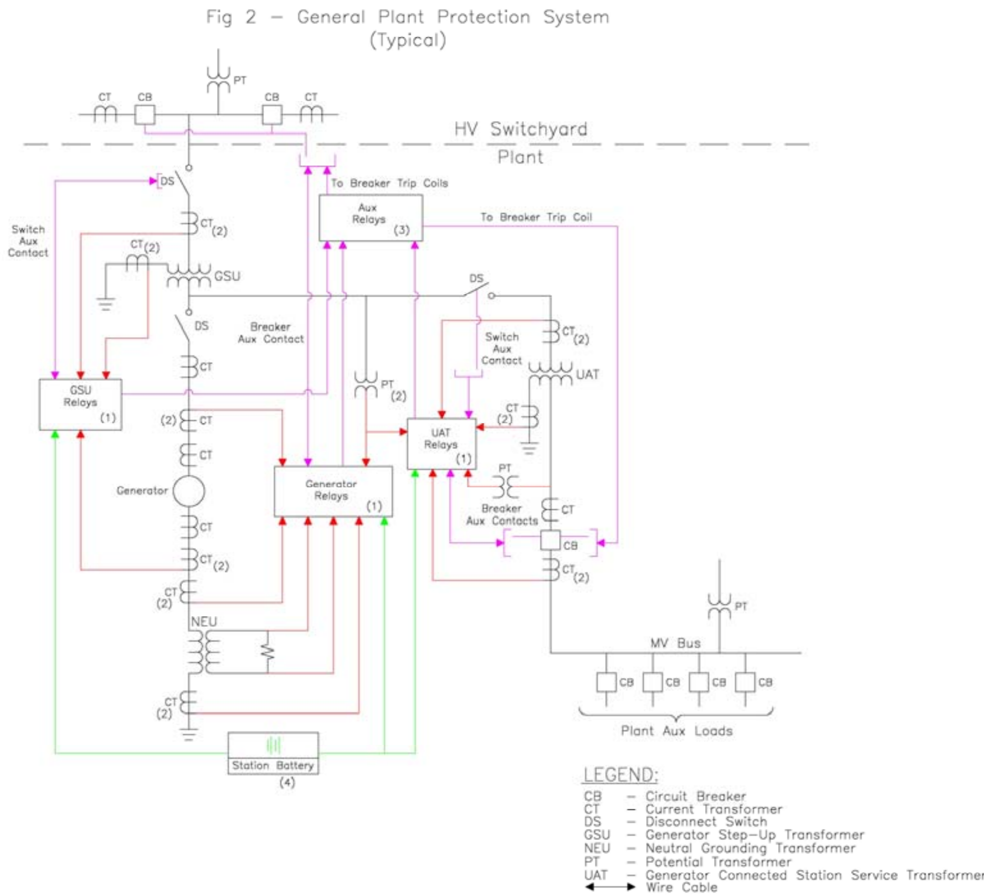
Figures

Figure 1: Typical Transmission System



For information on components, see ***[Figure 1 & 2 Legend – components of Protection Systems](#)***

Figure 2: Typical Generation System



Note: Figure 2 may show elements that are not included within PRC-005-2, and also may not be all-inclusive; see the Applicability section of the standard for specifics.

For information on components, see ***Figure 1 & 2 Legend – components of Protection Systems***

Figure 1 & 2 Legend – Components of Protection Systems

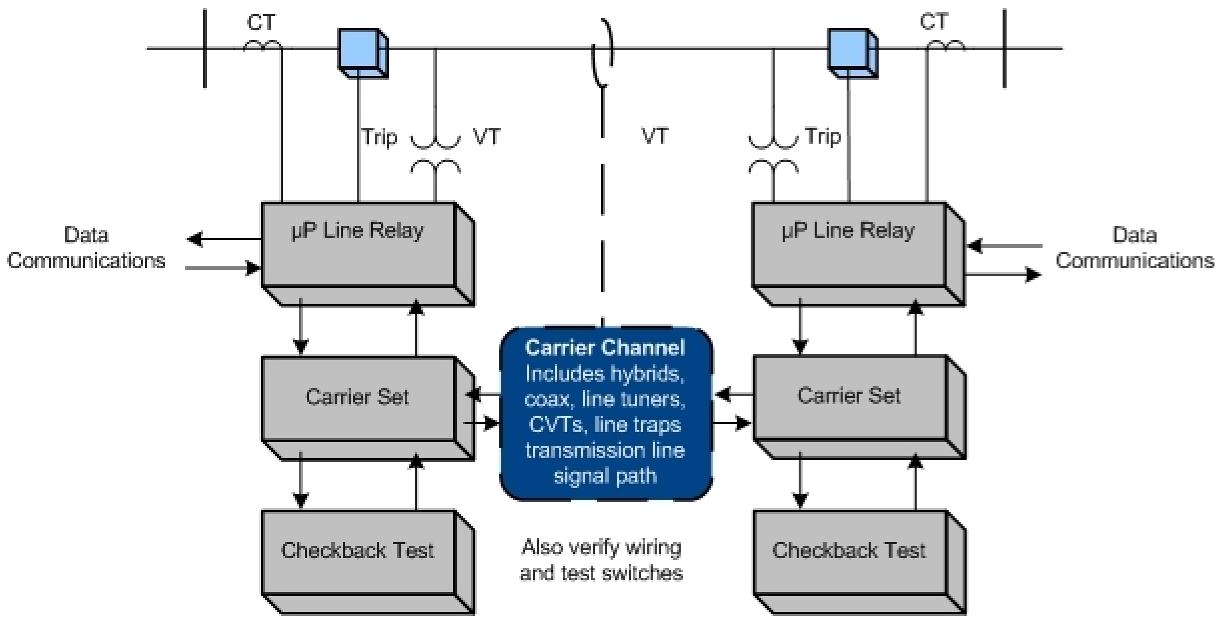
Number in Figure	Component of Protection System	Includes	Excludes
1	Protective relays which respond to electrical quantities	All protective relays that use current and/or voltage inputs from current & voltage sensors and that trip the 86, 94 or trip coil.	Devices that use non-electrical methods of operation including thermal, pressure, gas accumulation, and vibration. Any ancillary equipment not specified in the definition of Protection Systems. Control and/or monitoring equipment that is not a part of the automatic tripping action of the Protection System
2	Voltage and current sensing devices providing inputs to protective relays	The signals from the voltage & current sensing devices to the protective relay input.	Voltage & current sensing devices that are not a part of the Protection System, including sync-check systems, metering systems and data acquisition systems.
3	Control circuitry associated with protective functions	All control wiring (or other medium for conveying trip signals) associated with the tripping action of 86 devices, 94 devices or trip coils (from all parallel trip paths). This would include fiber-optic systems that carry a trip signal as well as hard-wired systems that carry trip current.	Closing circuits, SCADA circuits, other devices in control scheme not passing trip current
4	Station dc supply	Batteries and battery chargers and any control power system which has the function of supplying power to the protective relays, associated trip circuits and trip coils.	Any power supplies that are not used to power protective relays or their associated trip circuits and trip coils.
5	Communications systems necessary for correct operation of protective functions	Tele-protection equipment used to convey specific information, in the form of analog or digital signals, necessary for the correct operation of protective functions.	Any communications equipment that is not used to convey information necessary for the correct operation of protective functions.

Additional information can be found in References

Appendix A

The following illustrates the concept of overlapping verifications and tests as summarized in Section 10 of the paper. As an example, Figure A-1 shows protection for a critical transmission line by carrier blocking directional comparison pilot relaying. The goal is to verify the ability of the entire two-terminal pilot protection scheme to protect for line Faults, and to avoid over-tripping for Faults external to the transmission line zone of protection bounded by the current transformer locations.

Figure A-1



In this example (Figure A1), verification takes advantage of the self-monitoring features of microprocessor multifunction line relays at each end of the line. For each of the line relays themselves, the example assumes that the user has the following arrangements in place:

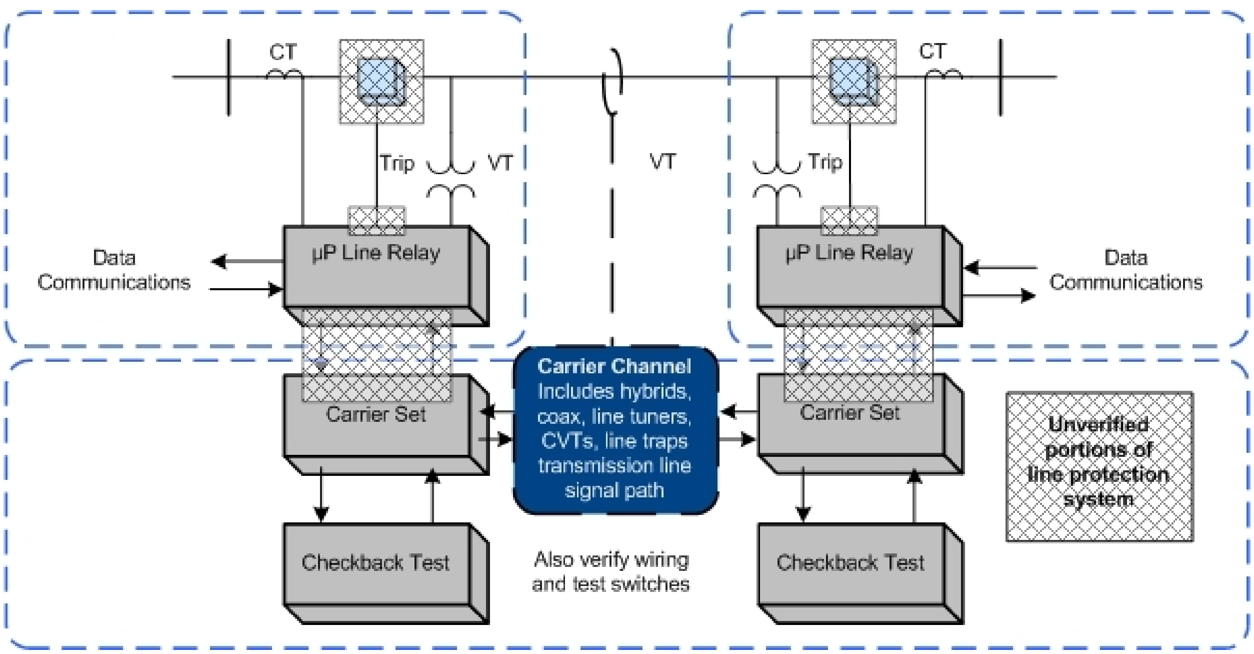
1. The relay has a data communications port that can be accessed from remote locations.
2. The relay has internal self-monitoring programs and functions that report failures of internal electronics, via communications messages or alarm contacts to SCADA.
3. The relays report loss of dc power, and the relays themselves or external monitors report the state of the dc battery supply.
4. The CT and PT inputs to the relays are used for continuous calculation of metered values of volts, amperes, plus Watts and VARs on the line. These metered values are reported by data communications. For maintenance, the user elects to compare these readings to those of other relays, meters, or DFRs. The other readings may be from redundant relaying or measurement systems or they may be derived from values in other protection zones. Comparison with other such readings to within required relaying accuracy verifies voltage & current sensing devices, wiring, and analog signal input processing of the relays. One

effective way to do this is to utilize the relay metered values directly in SCADA, where they can be compared with other references or state estimator values.

5. Breaker status indication from auxiliary contacts is verified in the same way as in (2). Status indications must be consistent with the flow or absence of current.
6. Continuity of the breaker trip circuit from dc bus through the trip coil is monitored by the relay and reported via communications.
7. Correct operation of the on-off carrier channel is also critical to security of the Protection System, so each carrier set has a connected or integrated automatic checkback test unit. The automatic checkback test runs several times a day. Newer carrier sets with integrated checkback testing check for received signal level and report abnormal channel attenuation or noise, even if the problem is not severe enough to completely disable the channel.

These monitoring activities plus the check-back test comprise automatic verification of all the Protection System elements that experience tells us are the most prone to fail. But, does this comprise a complete verification?

Figure A-2



The dotted boxes of Figure A-2 show the sections of verification defined by the monitoring and verification practices just listed. These sections are not completely overlapping, and the shaded regions show elements that are not verified:

1. The continuity of trip coils is verified, but no means is provided for validating the ability of the circuit breaker to trip if the trip coil should be energized.

2. Within each line relay, all the microprocessors that participate in the trip decision have been verified by internal monitoring. However, the trip circuit is actually energized by the contacts of a small telephone-type "ice cube" relay within the line protective relay. The microprocessor energizes the coil of this ice cube relay through its output data port and a transistor driver circuit. There is no monitoring of the output port, driver circuit, ice cube relay, or contacts of that relay. These components are critical for tripping the circuit breaker for a Fault.
3. The check-back test of the carrier channel does not verify the connections between the relaying microprocessor internal decision programs and the carrier transmitter keying circuit or the carrier receiver output state. These connections include microprocessor I/O ports, electronic driver circuits, wiring, and sometimes telephone-type auxiliary relays.
4. The correct states of breaker and disconnect switch auxiliary contacts are monitored, but this does not confirm that the state change indication is correct when the breaker or switch opens.

A practical solution for (1) and (2) is to observe actual breaker tripping, with a specified maximum time interval between trip tests. Clearing of naturally-occurring Faults are demonstrations of operation that reset the time interval clock for testing of each breaker tripped in this way. If Faults do not occur, manual tripping of the breaker through the relay trip output via data communications to the relay microprocessor meets the requirement for periodic testing.

PRC-005-X does not address breaker maintenance, and its Protection System test requirements can be met by energizing the trip circuit in a test mode (breaker disconnected) through the relay microprocessor. This can be done via a front-panel button command to the relay logic, or application of a simulated Fault with a relay test set. However, utilities have found that breakers often show problems during Protection System tests. It is recommended that Protection System verification include periodic testing of the actual tripping of connected circuit breakers.

Testing of the relay-carrier set interface in (3) requires that each relay key its transmitter, and that the other relay demonstrate reception of that blocking carrier. This can be observed from relay or DFR records during naturally occurring Faults, or by a manual test. If the checkback test sequence were incorporated in the relay logic, the carrier sets and carrier channel are then included in the overlapping segments monitored by the two relays, and the monitoring gap is completely eliminated.

Appendix B

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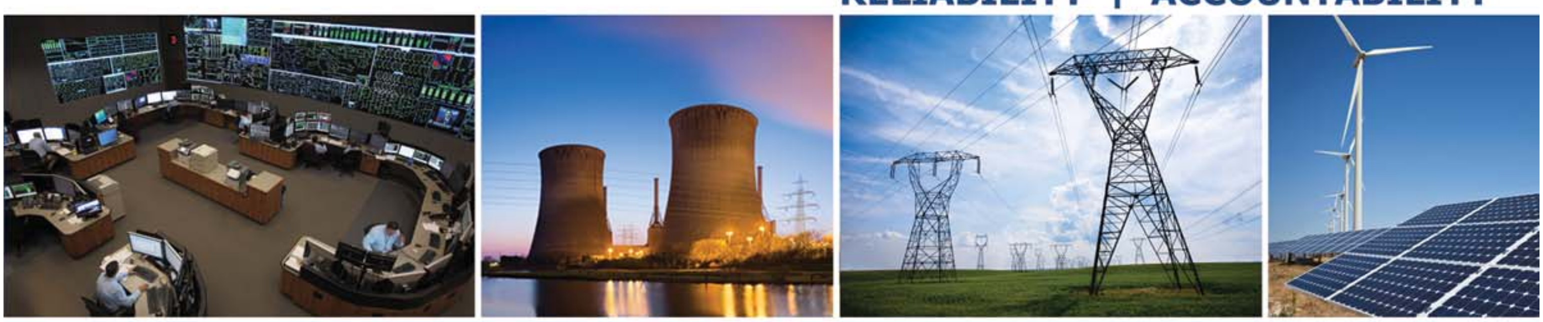
Supplementary Reference and FAQ

PRC-005-3 Protection System Maintenance

October 2013

RELIABILITY | ACCOUNTABILITY



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1. Introduction and Summary

Note: This supplementary reference for PRC-005-4~~3~~ is neither mandatory nor enforceable.

NERC currently has four Reliability Standards that are mandatory and enforceable in the United States and Canada and address various aspects of maintenance and testing of Protection and Control Systems.

These standards are:

PRC-005-1b — Transmission and Generation Protection System Maintenance and Testing

PRC-008-0 — Underfrequency Load Shedding Equipment Maintenance Programs

PRC-011-0 — UVLS System Maintenance and Testing

PRC-017-0 — Special Protection System Maintenance and Testing

While these standards require that applicable entities have a maintenance program for Protection Systems, and that these entities must be able to demonstrate they are carrying out such a program, there are no specifics regarding the technical requirements for Protection System maintenance programs. Furthermore, FERC Order 693 directed additional modifications respective to Protection System maintenance programs. PRC-005-3 will replace PRC-005-2 which combined and replaced PRC-005, PRC-008, PRC-011 and PRC-017. PRC-005-3 adds Automatic Reclosing to PRC-005-2. PRC-005-2 addressed these directed modifications and replaces PRC-005, PRC-008, PRC-011 and PRC-017.

FERC Order 758 further directed that maintenance of reclosing relays and sudden pressure relays that affect the reliable operation of the Bulk Power System be addressed. PRC-005-3 addresses this directive regarding reclosing relays, and, when approved, will supersede PRC-005-2. PRC-005-4 addresses this directive regarding sudden pressure relays and, when approved, will supersede PRC-005-3.

This document augments the Supplementary Reference and FAQ previously developed for PRC-005-2 by including discussion relevant to Automatic Reclosing added in PRC-005-3 and Sudden Pressure Relaying in PRC-005-4.

2. Need for Verifying Protection System Performance

Protective relays have been described as silent sentinels, and do not generally demonstrate their performance until a Fault or other power system problem requires that they operate to protect power system Elements, or even the entire Bulk Electric System (BES). Lacking Faults, switching operations or system problems, the Protection Systems may not operate, beyond static operation, for extended periods. A Misoperation - a false operation of a Protection System or a failure of the Protection System to operate, as designed, when needed - can result in equipment damage, personnel hazards, and wide-area Disturbances or unnecessary customer outages. Maintenance or testing programs are used to determine the performance and availability of Protection Systems.

Typically, utilities have tested Protection Systems at fixed time intervals, unless they had some incidental evidence that a particular Protection System was not behaving as expected. Testing practices vary widely across the industry. Testing has included system functionality, calibration of measuring devices, and correctness of settings. Typically, a Protection System must be visited at its installation site and, in many cases, removed from service for this testing.

Fundamentally, a Reliability Standard for Protection System Maintenance and Testing requires the performance of the maintenance activities that are necessary to detect and correct plausible age and service related degradation of the Protection System components, such that a properly built and commissioned Protection System will continue to function as designed over its service life.

Similarly station batteries, which are an important part of the station dc supply, are not called upon to provide instantaneous dc power to the Protection System until power is required by the Protection System to operate circuit breakers or interrupting devices to clear Faults or to isolate equipment.

2.1 Existing NERC Standards for Protection System Maintenance and Testing

For critical BES protection functions, NERC standards have required that each utility or asset owner define a testing program. The starting point is the existing Standard PRC-005, briefly restated as follows:

Purpose: To document and implement programs for the maintenance of all Protection Systems affecting the reliability of the Bulk Electric System (BES) so that these Protection Systems are kept in working order.

PRC-005-4~~3~~ is not specific on where the boundaries of the Protection Systems lie. However, the definition of Protection System in the NERC Glossary of Terms used in Reliability Standards indicates what must be included as a minimum.

At the beginning of the project to develop PRC-005-2, the definition of Protection System was:

Protective relays, associated communications Systems, voltage and current sensing devices, station batteries and dc control circuitry.

Applicability: Owners of generation and transmission Protection Systems.

Requirements: The owner shall have a documented maintenance program with test intervals. The owner must keep records showing that the maintenance was performed at the specified intervals.

2.2 Protection System Definition

The most recently approved definition of Protection Systems is:

- Protective relays which respond to electrical quantities,
- Communications systems necessary for correct operation of protective functions,
- Voltage and current sensing devices providing inputs to protective relays,
- Station dc supply associated with protective functions (including station batteries, battery chargers, and non-battery-based dc supply), and
- Control circuitry associated with protective functions through the trip coil(s) of the circuit breakers or other interrupting devices.

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:

"*…that are installed for the purpose of detecting Faults on BES Elements (lines, buses, transformers, etc.).*"

The drafting team intends that this standard will follow with any definition of the Bulk Electric System. There should be no ambiguity; if the Element is a BES Element, then the Protection System protecting that Element should then be included within this standard. If there is regional variation to the definition, then there will be a corresponding regional variation to the Protection Systems that fall under this standard.

There is no way for the Standard Drafting Team to know whether a specific 230KV line, 115KV line (even 69KV line), for example, should be included or excluded. Therefore, the team set the clear intent that the standard language should simply be applicable to Protection Systems for BES Elements.

The BES is a NERC defined term that, from time to time, may undergo revisions. Additionally, there may even be regional variations that are allowed in the present and future definitions. See the NERC Glossary of Terms for the present, in-force definition. See the applicable Regional Reliability Organization for any applicable allowed variations.

While this standard will undergo revisions in the future, this standard will not attempt to keep up with revisions to the NERC definition of BES, but, rather, simply make BES Protection Systems applicable.

The Standard is applied to Generator Owners (GO) and Transmission Owners (TO) because GOs and TOs have equipment that is BES equipment. The standard brings in Distribution Providers (DP) because, depending on the station configuration of a particular substation, there may be Protection System equipment installed at a non-transmission voltage level (Distribution Provider equipment) that is wholly or partially installed to protect the BES. PRC-005-~~3~~4 would apply to this equipment. An example is underfrequency load-shedding, which is frequently applied well down into the distribution system to meet PRC-007-0.

PRC-005-2 replaced the existing PRC-005, PRC-008, PRC-011 and PRC-017. Much of the original intent of those standards was carried forward whenever it was possible to continue the intent without a disagreement with FERC Order 693. For example, the original PRC-008 was constructed quite differently than the original PRC-005. The drafting team agrees with the intent of this and notes that distributed tripping schemes would have to exhibit multiple failures to trip before they would prove to be significant, as opposed to a single failure to trip of, for example, a transmission Protection System Bus Differential lock-out relay. While many failures of these distribution breakers could add up to be significant, it is also believed that distribution breakers are operated often on just Fault clearing duty; and, therefore, the distribution circuit breakers are operated at least as frequently as stipulated in any requirement in this standard.

Additionally, since PRC-005-2 replaced PRC-011, it will be important to make the distinction between under-voltage Protection Systems that protect individual Loads and Protection Systems that are UVLS schemes that protect the BES. Any UVLS scheme that had been applicable under PRC-011 is now applicable under PRC-005-2. An example of an under-voltage load-shedding scheme that is not applicable to this standard is one in which the tripping action was intended to prevent low distribution voltage to a specific Load from a Transmission system that was intact except for the line that was out of service, as opposed to preventing a Cascading outage or Transmission system collapse.

It had been correctly noted that the devices needed for PRC-011 are the very same types of devices needed in PRC-005.

Thus, a standard written for Protection Systems of the BES can easily make the needed requirements for Protection Systems, and replace some other standards at the same time.

2.3.1 Frequently Asked Questions:

What exactly is the BES, or Bulk Electric System?

BES is the abbreviation for Bulk Electric System. BES is a term in the Glossary of Terms used in Reliability Standards, and is not being modified within this draft standard.
NERC's approved definition of Bulk Electric System is:

As defined by the Regional Reliability Organization, the electrical generation resources, transmission lines, Interconnections with neighboring Systems, and associated equipment, generally operated at voltages of 100 kV or higher. Radial transmission Facilities serving only Load with one transmission source are generally not included in this definition.

The BES definition is presently undergoing the process of revision.

Each regional entity implements a definition of the Bulk Electric System that is based on this NERC definition; in some cases, supplemented by additional criteria. These regional definitions have been documented and provided to FERC as part of a *June 14, 2007 Informational Filing*.

Why is Distribution Provider included within the Applicable Entities and as a responsible entity within several of the requirements? Wouldn't anyone having relevant Facilities be a Transmission Owner?

Depending on the station configuration of a particular substation, there may be Protection System equipment installed at a non-transmission voltage level (Distribution Provider equipment) that is wholly or partially installed to protect the BES. ~~PRC-005-3~~PRC-005-4 applies to this equipment. An example is underfrequency load-shedding, which is frequently applied well down into the distribution system to meet PRC-007-0.

We have an under voltage load-shedding (UVLS) system in place that prevents one of our distribution substations from supplying extremely low voltage in the case of a specific transmission line outage. The transmission line is part of the BES. Does this mean that our UVLS system falls within this standard?

The situation, as stated, indicates that the tripping action was intended to prevent low distribution voltage to a specific Load from a Transmission System that was intact, except for the line that was out of service, as opposed to preventing Cascading outage or Transmission System Collapse.

This standard is not applicable to this UVLS.

We have a UFLS or UVLS scheme that sheds the necessary Load through distribution-side circuit breakers and circuit reclosers. Do the trip-test requirements for circuit breakers apply to our situation?

No. Distributed tripping schemes would have to exhibit multiple failures to trip before they would prove to be significant, as opposed to a single failure to trip of, for example, a transmission Protection System bus differential lock-out relay. While many failures of these distribution breakers could add up to be significant, it is also believed that distribution breakers are operated often on just Fault clearing duty; and, therefore, the distribution circuit breakers are operated at least as frequently as any requirements that might have appeared in this standard.

We have a UFLS scheme that, in some locales, sheds the necessary Load through non-BES circuit breakers and, occasionally, even circuit switchers. Do the trip-test requirements for circuit breakers apply to our situation?

If your "non-BES circuit breaker" has been brought into this standard by the inclusion of UFLS requirements, and otherwise would not have been brought into this standard, then the answer is that there are no trip-test requirements. For these devices that are otherwise non-BES assets, these tripping schemes would have to exhibit multiple failures to trip before they would prove to be as significant as, for example, a single failure to trip of a transmission Protection System bus differential lock-out relay.

How does the "Facilities" section of "Applicability" track with the standards that will be retired once PRC-005-2 becomes effective?

In establishing PRC-005-2, the drafting team combined legacy standards PRC-005-1b, PRC-008-0, PRC-011-0, and PRC-017-0. The merger of the subject matter of these standards is reflected in Applicability 4.2.

The intent of the drafting team is that the legacy standards be reflected in PRC-005-2 as follows:

- Applicability of PRC-005-1b for Protection Systems relating to non-generator elements of the BES is addressed in 4.2.1;
- Applicability of PRC-008-0 for underfrequency load shedding systems is addressed in 4.2.2;
- Applicability of PRC-011-0 for undervoltage load shedding relays is addressed in 4.2.3;
- Applicability of PRC-017-0 for Special Protection Systems is addressed in 4.2.4;
- Applicability of PRC-005-1b for Protection Systems for BES generators is addressed in 4.2.5.

2.4 Applicable Relays

The NERC Glossary definition has a Protection System including relays, dc supply, current and voltage sensing devices, dc control circuitry and associated communications circuits. The relays to which this standard applies are those protective relays that respond to electrical quantities and provide a trip output to trip coils, dc control circuitry or associated communications equipment. This definition extends to IEEE Device No. 86 (lockout relay) and IEEE Device No. 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.

Relays that respond to non-electrical inputs or impulses (such as, but not limited to, vibration, ~~pressure,~~ seismic, thermal or gas accumulation) are not included.

Automatic Reclosing is addressed in PRC-005-3 by explicitly addressing them outside the definition of Protection System. The specific locations for applicable Automatic Reclosing are addressed in Applicability Section 4.2.7~~6~~.

Sudden Pressure R~~r~~elaying is addressed in PRC-005-4 by explicitly addressing them outside the definition of ~~Protectin~~Protection System. The specific locations for applicable Sudden Pressure Relaying are addressed in Applicability Section 4.2.1, 4.2.5 and 4.2.6.

2.4.1 Frequently Asked Questions:

Are power circuit reclosers, reclosing relays, closing circuits and auto-restoration schemes covered in this Standard?

Yes. Automatic Reclosing includes reclosing relays and the associated dc control circuitry. Section 4.2.6 of the Applicability specifically limits the applicable reclosing relays to:

4.2.6 Automatic Reclosing

4.2.6.1 Automatic Reclosing applied on the terminals of Elements connected to the BES bus located at generating plant substations where the total installed gross generating plant capacity is greater than the gross capacity of the largest BES generating unit within the Balancing Authority Area.

4.2.6.2 Automatic Reclosing applied on the terminals of all BES Elements at substations one bus away from generating plants specified in Section 4.2.6.1 when the substation is less than 10 circuit-miles from the generating plant substation.

4.2.6.3 Automatic Reclosing applied as an integral part of a SPS specified in Section 4.2.4.

Further, Footnote 1 to Applicability Section 4.2.6 establishes that Automatic Reclosing addressed in 4.2.6.1 and 4.2.6.2 may be excluded if the equipment owner can demonstrate that a close-in three-phase fault present for twice the normal clearing time (capturing a minimum trip-close-trip time delay) does not result in a total loss of gross generation in the Interconnection exceeding the gross capacity of the largest BES unit within the Balancing Authority Area where the Automatic Reclosing is applied.

The Applicability as detailed above was recommended by the NERC System Analysis and Modeling Subcommittee (SAMS) after a lengthy review of the use of reclosing within the BES. SAMS concluded that automatic reclosing is largely implemented throughout the BES as an operating convenience, and that automatic reclosing mal-performance affects BES reliability only when the reclosing is part of a Special Protection System, or when premature autoreclosing has the potential to cause generating unit or plant instability. A technical report, “Considerations for Maintenance and Testing of Autoreclosing Schemes — November 2012”, is referenced in PRC-005-3 and provides a more detailed discussion of these concerns.

How do I interpret Applicability Section 4.2.6 to determine applicability in the following examples:

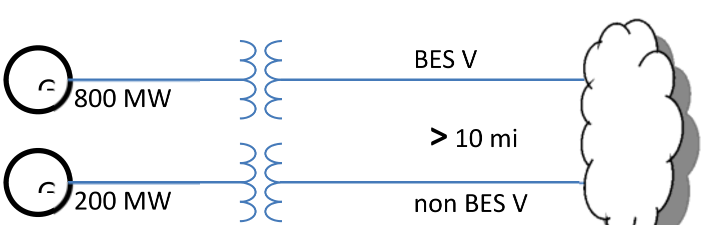
At my generating plant substation, I have a total of 800 MW connected to one voltage level and 200 MW connected to another voltage level. How do I determine my gross capacity? Where do I consider Automatic Reclosing to be applicable?

Scenario number 1:

The 800 MW of generation is connected to a BES voltage level bus, the 200 MW unit is connected to a non-BES voltage level bus, and there is no connection between the two buses locally or within 10 circuit miles from the generating plant substation. The largest single unit in the BA area is 750 MW.

In this case, the total installed gross generating capacity would be 800 MW. The two units are essentially independent plants.

The BES voltage level bus is considered to be the bus to which the 800 MW of generation is connected. Any BES Automatic Reclosing at this location, as well as other locations within 10 circuit miles, is considered to be applicable because 800 MW exceeds the largest single unit in the BA area.



[Essentially independent plants]

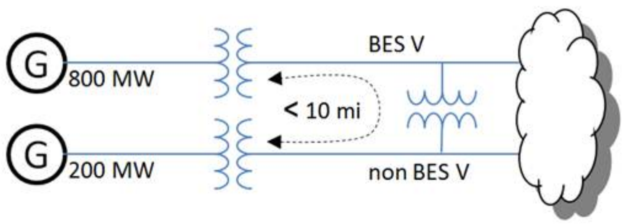
Gross Capacity	Automatic Reclosing in scope
800 MW	BES V

Scenario number 2:

The 800 MW of generation is connected to a BES voltage level bus, the 200 MW unit is connected to a non-BES voltage level bus, and there is a connection between the two buses locally or within 10 circuit miles from the generating plant substation. The largest single unit in the BA area is 750 MW.

In this case, reclosing into a fault on the BES system could impact the stability of the non-BES-connected generating units. Therefore, the total installed gross generating capacity would be 1000 MW.

The BES voltage level bus is considered to be the bus to which the 800 MW of generation is connected. Any BES Automatic Reclosing at this location, as well as other locations within 10 circuit miles, is considered to be applicable because total of 1000 MW exceeds the largest single unit in the BA area. However, the Automatic Reclosing on the non-BES voltage level bus is not applicable.



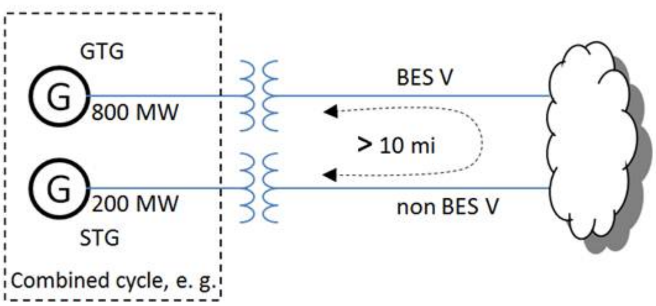
Gross Capacity	Automatic Reclosing in scope
1000 MW	BES V

Scenario number 3:

The 800 MW of generation is connected to a BES voltage level bus, the 200 MW unit is connected to a non-BES voltage level bus, and there is no connection between the two buses locally or within 10 circuit miles from the generating plant substation but the generating units connected at the BES voltage level do not operate independently of the units connected at the non BES voltage level (e.g., a combined cycle facility where 800 MW of combustion turbines are connected at a BES voltage level whose exhaust is used to power a 200 MW steam unit connected to a non BES voltage level. The largest single unit in the BA area is 750 MW.

In this case, the total installed gross generating capacity would be 1000 MW. Therefore, reclosing into a fault on the BES voltage level would result in a loss of the 800 MW combustion turbines and subsequently result in the loss of the 200 MW steam unit because of the loss of the heat source to its boiler.

The BES voltage level bus is considered to be the bus to which the 800 MW of generation is connected. Any BES Automatic Reclosing at this location, as well as other locations within 10 circuit miles, is considered to be applicable because total of 1000 MW exceeds the largest single unit in the BA area. However, the Automatic Reclosing on the non-BES voltage level bus is not applicable.



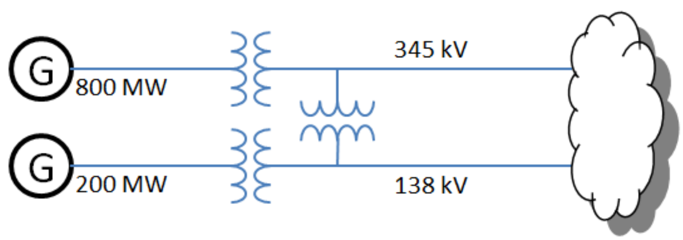
Gross Capacity	Automatic Reclosing in scope
1000 MW	BES V

Scenario 4

The 800 MW of generation is connected at 345 kV and the 200 MW is connected at 138 kV with an autotransformer at the generating plant substation connecting the two voltage levels. The largest single unit in the BA area is 900 MW.

In this case, the total installed gross generating capacity would be 1000 MW and section 4.2.6.1 would be applicable to both the 345 kV Automatic Reclosing Components and the 138 kV Automatic Reclosing Components, since the total capacity of 1000 MW is larger than the largest single unit in the BA area.

However, if the 345 kV and the 138 kV systems can be shown to be uncoupled such that the 138 kV reclosing relays will not affect the stability of the 345 kV generating units then the 138 kV Automatic Reclosing Components need not be included per section 4.2.6.1.



Gross Capacity	**Automatic Reclosing in scope**
1000 MW	BOTH*

* The study detailed in Footnote 1 of the draft standard may eliminate the 138 kV Automatic Reclosing Components and/or the 345 kV Automatic Reclosing Components

Why does 4.2.6.2 specify "10 circuit miles"?

As noted in "Considerations for Maintenance and Testing of Autoreclosing Schemes — November 2012", transmission line impedance on the order of one mile away typically provides adequate impedance to prevent generating unit instability and a 10 mile threshold provides sufficient margin.

Should I use MVA or MW when determining the installed gross generating plant capacity?

Be consistent with the rating used by the Balancing Authority for the largest BES generating unit within their area.

What value should we use for generating plant capacity in 4.2.6.1?

Use the value reported to the Balance Authority for generating plant capacity for planning and modeling purposes. This can be nameplate or other values based on generating plant limitations such as boiler or turbine ratings.

What is considered to be "one bus away" from the generation?

The BES voltage level bus is considered to be the generating plant substation bus to which the generator step-up transformer is connected. "One bus away" is the next bus, connected by either a transmission line or transformer.

I use my protective relays only as sources of metered quantities and breaker status for SCADA and EMS through a substation distributed RTU or data concentrator to the control center. What are the maintenance requirements for the relays?

This standard addresses Protection Systems that are installed for the purpose of detecting Faults on BES Elements (lines, buses, transformers, etc.). Protective relays, providing only the functions mentioned in the question, are not included.

Are Reverse Power Relays installed on the low-voltage side of distribution banks considered to be components of "Protection Systems that are installed for the purpose of detecting Faults on BES Elements (lines, buses, transformers, etc.)"?

Reverse power relays are often installed to detect situations where the transmission source becomes deenergized and the distribution bank remains energized from a source on the low-voltage side of the transformer and the settings are calculated based on the charging current of the transformer from the low-voltage side. Although these relays may operate as a result of a fault on a BES element, they are not 'installed for the purpose of detecting' these faults.

~~***Is a Sudden Pressure Relay an auxiliary tripping relay?***~~

~~No. IEEE C37.2-2008 assigns the Device No. 94 to auxiliary tripping relays. Sudden pressure relays are assigned Device No. 63. Sudden pressure relays are presently excluded from the standard because it does not utilize voltage and/or current measurements to determine anomalies. Devices that use anything other than electrical detection means are excluded. The trip path from a sudden pressure device is a part of the Protection System control circuitry. The sensing element is omitted from PRC-005-3 testing requirements because the SDT is unaware of industry-recognized testing protocol for the sensing elements. The SDT believes that Protection Systems that trip (or can trip) the BES should be included. This position is consistent with the currently-~~

~~approved PRC-005-1b, consistent with the SAR for Project 2007-17, and understands this to be consistent with the position of FERC staff.~~

Why is the maintenance of Sudden Pressure Relaying being addressed in PRC-005-4?

Proper performance of Sudden Pressure Relaying supports the reliability of the BES because fault pressure relays can detect rapid changes in gas pressure, oil pressure, or oil flow that are indicative of faults within liquid-filled, wire-wound equipment such as turn-to-turn faults which may be undetected by Protection Systems. Additionally, Sudden Pressure Relaying can quickly detect faults and operate to limit damage to liquid-filled, wire-wound equipment.

What type of devices are classified as fault pressure relay?

There are three main types of fault pressure relays; rapid gas pressure rise, rapid oil pressure rise, and rapid oil flow devices.

Rapid gas pressure devices monitor the pressure in the space above the oil (or other liquid), and initiate tripping action for a rapid rise in gas pressure resulting from the rapid expansion of the liquid caused by a fault. The sensor is located in the gas space.

Rapid oil pressure devices monitor the pressure in the oil (or other liquid), and initiate tripping action for a rapid pressure rise caused by a fault. The sensor is located in the liquid.

Rapid oil flow devices (“Buchholz”) monitor the liquid flow between a transformer/reactor and its conservator. Normal liquid flow occurs continuously with ambient temperature changes and with internal heating from loading and does not operate the rapid oil flow device. However, when an internal arc happens a sudden expansion of liquid can be monitored as rapid liquid flow from the transformer into the conservator resulting in actuation of the rapid oil flow device.

Are sudden pressure relays that only initiate an alarm included in the scope of PRC-005-4?

No, the definition of Sudden Pressure Relaying specifies only those that trip an interrupting device(s) to isolate the equipment it is monitoring.

Is Sudden Pressure Relaying installed on distribution transformers included in PRC-005-4?

No, Applicability 4.2.1, 4.2.5.2, 4.2.5.3, 4.2.6.1, explicitly describe what Sudden Pressure Relaying is included within the standard.

~~My~~ Are non-electrical sensing devices (other than fault pressure relays) such as ~~mechanical device~~as low oil level or high winding temperatures included in PRC-005-4?~~does not operate electrically and does not have calibration settings; what maintenance activities apply?~~

No, based on the SPCS technical document, “Sudden Pressure Relays and Other Devices that Respond to Non-Electrical Quantities – December 2013” the only applicable non-electrical sensing devices are fault pressure relays. ~~You must conduct a test(s) to verify the integrity of any trip circuit that is a part of a Protection System. This standard does not cover circuit breaker maintenance or transformer maintenance. The standard also does not presently cover testing of devices, such as sudden pressure relays (63), temperature relays (49), and other relays which respond to mechanical parameters, rather than electrical parameters. There is an expectation that Fault pressure relays and other non-electrically initiated devices may become part of some maintenance standard. This standard presently covers trip paths. It might seem incongruous to test a trip path without a present requirement to test the device; and, thus, be arguably more work for nothing. But one simple test to verify the integrity of such a trip path could be (but is not limited to) a voltage presence test, as a dc voltage monitor might do if it were installed monitoring that same circuit.~~

The standard specifically mentions auxiliary and lock-out relays. What is an auxiliary tripping relay?

An auxiliary relay, IEEE Device No. 94, is described in IEEE Standard C37.2-2008 as: "A device that functions to trip a circuit breaker, contactor, or equipment; to permit immediate tripping by other devices; or to prevent immediate reclosing of a circuit interrupter if it should open automatically, even though its closing circuit is maintained closed."

What is a lock-out relay?

A lock-out relay, IEEE Device No. 86, is described in IEEE Standard C37.2 as: "A device that trips and maintains the associated equipment or devices inoperative until it is reset by an operator, either locally or remotely."

3. Protection System and Automatic Reclosing Product Generations

The likelihood of failure and the ability to observe the operational state of a critical Protection System and Automatic Reclosing both depend on the technological generation of the relays, as well as how long they have been in service. Unlike many other transmission asset groups, protection and control systems have seen dramatic technological changes spanning several generations. During the past 20 years, major functional advances are primarily due to the introduction of microprocessor technology for power system devices, such as primary measuring relays, monitoring devices, control Systems, and telecommunications equipment.

Modern microprocessor-based relays have six significant traits that impact a maintenance strategy:

- Self monitoring capability - the processors can check themselves, peripheral circuits, and some connected substation inputs and outputs, such as trip coil continuity. Most relay users are aware that these relays have self monitoring, but are not focusing on exactly what internal functions are actually being monitored. As explained further below, every element critical to the Protection System must be monitored, or else verified periodically.
- Ability to capture Fault records showing how the Protection System responded to a Fault in its zone of protection, or to a nearby Fault for which it is required not to operate.
- Ability to meter currents and voltages, as well as status of connected circuit breakers, continuously during non-Fault times. The relays can compute values, such as MW and MVAR line flows, that are sometimes used for operational purposes, such as SCADA.
- Data communications via ports that provide remote access to all of the results of Protection System monitoring, recording and measurement.
- Ability to trip or close circuit breakers and switches through the Protection System outputs, on command from remote data communications messages, or from relay front panel button requests.
- Construction from electronic components, some of which have shorter technical life or service life than electromechanical components of prior Protection System generations.

There have been significant advances in the technology behind the other components of Protection Systems. Microprocessors are now a part of battery chargers, associated communications equipment, voltage and current-measuring devices, and even the control circuitry (in the form of software-latches replacing lock-out relays, etc.).

Any Protection System component can have self-monitoring and alarming capability, not just relays. Because of this technology, extended time intervals can find their way into all components of the Protection System.

This standard also recognizes the distinct advantage of using advanced technology to justifiably defer or even eliminate traditional maintenance. Just as a hand-held calculator does not require routine testing and calibration, neither does a calculation buried in a microprocessor-based device that results in a “lock-out.” Thus, the software-latch 86 that replaces an electro-mechanical 86 does not require routine trip testing. Any trip circuitry associated with the “soft

86” would still need applicable verification activities performed, but the actual “86” does not have to be “electrically operated” or even toggled.

4. Definitions

Protection System Maintenance Program (PSMP) — An ongoing program by which Protection System,~~ and~~ A~~a~~utomatic R~~r~~eclosing and S~~s~~udden P~~p~~ressure R~~r~~elaying C~~c~~omponents are kept in working order and proper operation of malfunctioning C~~c~~omponents is restored. A maintenance program for a specific C~~c~~omponent includes one or more of the following activities:

- Verify — Determine that the C~~c~~omponent is functioning correctly.
- Monitor — Observe the routine in-service operation of the C~~c~~omponent.
- Test — Apply signals to a C~~c~~omponent to observe functional performance or output behavior, or to diagnose problems.
- Inspect — Detect visible signs of ~~c~~Component failure, reduced performance and degradation.
- Calibrate — Adjust the operating threshold or measurement accuracy of a measuring element to meet the intended performance requirement.

Automatic Reclosing –

Includes the following Components:

- Reclosing relay
- Control circuitry associated with the reclosing relay~~-~~.

Sudden Pressure Relaying – A system that trips an interrupting device(s) to isolate the equipment it is monitoring and includes the following Components:

- Fault pressure relay – a mechanical relay or device that detecting rapid changes in gas pressure, oil pressure, or oil flow that are indicative of faults within liquid-filled, wire-wound equipment
- Control circuitry associated with a fault pressure relay

Unresolved Maintenance Issue – A deficiency identified during a maintenance activity that causes the component to not meet the intended performance, cannot be corrected during the maintenance interval, and requires follow-up corrective action.

Segment – Components of a consistent design standard, or a particular model or type from a single manufacturer that typically share other common elements. Consistent performance is expected across the entire population of a Segment. A Segment must contain at least sixty (60) individual Components.

Component Type – ~~Either any~~

- Any one of the five specific elements of ~~the~~ a Protection System.
- Any one of the two ~~definition or any one of the two~~ specific elements of~~ the~~ Automatic Reclosing. ~~definition~~
- Any one of the two specific elements of Sudden Pressure Relaying.~~-~~

Component – Any individual discrete piece of equipment included in a Protection System, Automatic Reclosing, or Sudden Pressure Relaying.

~~A Component is any individual discrete piece of equipment included in a Protection System or in Automatic Reclosing, including but not limited to a protective relay, reclosing relay, or current sensing device. The designation of what constitutes a control circuit Component is dependent upon how an entity performs and tracks the testing of the control circuitry. Some entities test their control circuits on a breaker basis whereas others test their circuitry on a local zone of protection basis. Thus, entities are allowed the latitude to designate their own definitions of control circuit Components. Another example of where the entity has some discretion on determining what constitutes a single Component is the voltage and current sensing devices, where the entity may choose either to designate a full three-phase set of such devices or a single device as a single Component.~~

Countable Event – A failure of a Component requiring repair or replacement, any condition discovered during the maintenance activities in Tables 1-1 through 1-5, Table 3, Tables 4-1 through 4-2, and Table ~~4~~5, which requires corrective action or a Protection System Misoperation attributed to hardware failure or calibration failure. Misoperations due to product design errors, software errors, relay settings different from specified settings, Protection System Component, ~~or~~ Automatic Reclosing or Sudden Pressure Relaying configuration or application errors are not included in Countable Events.

4.1 Frequently Asked Questions:

Why does PRC-005-4~~3~~ not specifically require maintenance and testing procedures, as reflected in the previous standard, PRC-005-1?

PRC-005-1 does not require detailed maintenance and testing procedures, but instead requires summaries of such procedures, and is not clear on what is actually required. PRC-005-4~~3~~ requires a documented maintenance program, and is focused on establishing requirements rather than prescribing methodology to meet those requirements. Between the activities identified in the Tables 1-1 through 1-5, Table 2, Table 3, and Table 4 (collectively the "Tables"), and the various components of the definition established for a "Protection System Maintenance Program," PRC-005-4~~3~~ establishes the activities and time basis for a Protection System Maintenance Program to a level of detail not previously required.

Please clarify what is meant by "restore" in the definition of maintenance.

The description of "restore" in the definition of a Protection System Maintenance Program addresses corrective activities necessary to assure that the component is returned to working order following the discovery of its failure or malfunction. The Maintenance Activities specified in the Tables do not present any requirements related to Restoration; R5 of the standard does require that the entity "shall demonstrate efforts to correct any identified Unresolved Maintenance Issues." Some examples of restoration (or correction of Unresolved Maintenance Issues) include, but are not limited to, replacement of capacitors in distance relays to bring them to working order; replacement of relays, or other Protection System components, to bring the Protection System to working order; upgrade of electromechanical or solid-state protective relays to microprocessor-based relays following the discovery of failed components. Restoration, as used in this context, is not to be confused with restoration rules as used in system operations. Maintenance activity necessarily includes both the detection of problems and the repairs needed to eliminate those problems. This standard does not identify all of the Protection System problems that must be detected and eliminated, rather it is the intent of this standard that an entity determines the necessary working order for their various devices, and keeps them in working order. If an equipment item is repaired or replaced, then the entity can restart the maintenance-time-interval-clock, if desired; however, the replacement of equipment does not remove any documentation requirements that would have been required to verify compliance with time-interval requirements. In other words, do not discard maintenance data that goes to verify your work.

The retention of documentation for new and/or replaced equipment is all about proving that the maintenance intervals had been in compliance. For example, a long-range plan of upgrades might lead an entity to ignore required maintenance; retaining the evidence of prior maintenance that existed before any retirements and upgrades proves compliance with the standard.

Please clarify what is meant by "…demonstrate efforts to correct an Unresolved Maintenance Issue…"; why not measure the completion of the corrective action?

Management of completion of the identified Unresolved Maintenance Issue is a complex topic that falls outside of the scope of this standard. There can be any number of supply, process and management problems that make setting repair deadlines impossible. The SDT specifically chose the phrase "demonstrate efforts to correct" (with guidance from NERC Staff) because of the concern that many more complex Unresolved Maintenance Issues might require greater than the remaining maintenance interval to resolve (and yet still be a "closed-end process"). For example, a problem might be identified on a VRLA battery during a six-month check. In instances such as one that requiring battery replacement as part of the long-term resolution, it is highly unlikely that the battery could be replaced in time to meet the six-calendar-month requirement for this maintenance activity. The SDT does not believe entities should be found in violation of a maintenance program requirement because of the inability to complete a remediation program within the original maintenance interval. The SDT does believe corrective actions should be timely, but concludes it would be impossible to postulate all possible remediation projects; and, therefore, impossible to specify bounding time frames for resolution of all possible Unresolved Maintenance Issues, or what documentation might be sufficient to provide proof that effective corrective action is being undertaken.

5. Time-Based Maintenance (TBM) Programs

Time-based maintenance is the process in which Protection System, ~~and~~ Automatic Reclosing and Sudden Pressure Relaying Components are maintained or verified according to a time schedule. The scheduled program often calls for technicians to travel to the physical site and perform a functional test on Protection System components. However, some components of a TBM program may be conducted from a remote location - for example, tripping a circuit breaker by communicating a trip command to a microprocessor relay to determine if the entire Protection System tripping chain is able to operate the breaker. Similarly, all Protection System, ~~and Automatic Reclosing~~ and Sudden Pressure Relaying Components can have the ability to remotely conduct tests, either on-command or routinely; the running of these tests can extend the time interval between hands-on maintenance activities.

5.1 Maintenance Practices

Maintenance and testing programs often incorporate the following types of maintenance practices:

- TBM – time-based maintenance – externally prescribed maximum maintenance or testing intervals are applied for components or groups of components. The intervals may have been developed from prior experience or manufacturers' recommendations. The TBM verification interval is based on a variety of factors, including experience of the particular asset owner, collective experiences of several asset owners who are members of a country or regional council, etc. The maintenance intervals are fixed and may range in number of months or in years.

  TBM can include review of recent power system events near the particular terminal. Operating records may verify that some portion of the Protection System has operated correctly since the last test occurred. If specific protection scheme components have demonstrated correct performance within specifications, the maintenance test time clock can be reset for those components.

- PBM – Performance-Based Maintenance - intervals are established based on analytical or historical results of TBM failure rates on a statistically significant population of similar components. Some level of TBM is generally followed. Statistical analyses accompanied by adjustments to maintenance intervals are used to justify continued use of PBM-developed extended intervals when test failures or in-service failures occur infrequently.

- CBM – condition-based maintenance – continuously or frequently reported results from non-disruptive self-monitoring of components demonstrate operational status as those components remain in service. Whatever is verified by CBM does not require manual testing, but taking advantage of this requires precise technical focus on exactly what parts are included as part of the self-diagnostics. While the term "Condition-Based-Maintenance" (CBM) is no longer used within the standard itself, it is important to note that the concepts of CBM are a part of the standard (in the form of extended time intervals through status-monitoring). These extended time intervals are only allowed (in the absence of PBM) if the condition of the device is monitored (CBM). As a consequence of the "monitored-basis-time-intervals" existing within the standard, the explanatory

discussions within this Supplementary Reference concerned with CBM will remain in this reference and are discussed as CBM.

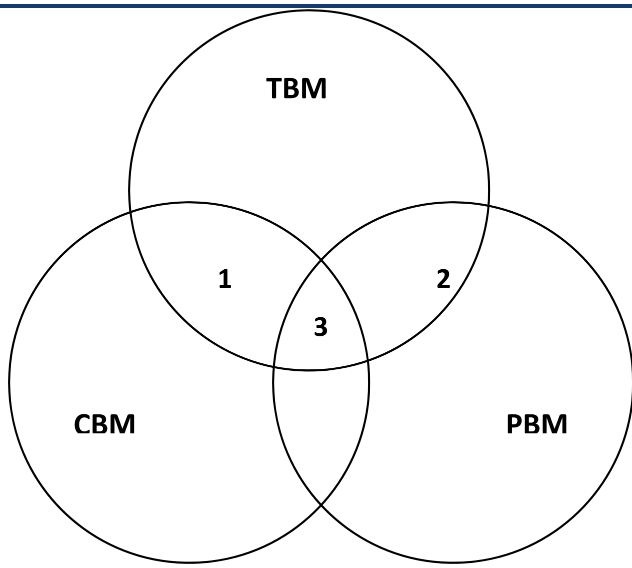
Microprocessor-based Protection System or Automatic Reclosing Components that perform continuous self-monitoring verify correct operation of most components within the device. Self-monitoring capabilities may include battery continuity, float voltages, unintentional grounds, the ac signal inputs to a relay, analog measuring circuits, processors and memory for measurement, protection, and data communications, trip circuit monitoring, and protection or data communications signals (and many, many more measurements). For those conditions, failure of a self-monitoring routine generates an alarm and may inhibit operation to avoid false trips. When internal components, such as critical output relay contacts, are not equipped with self-monitoring, they can be manually tested. The method of testing may be local or remote, or through inherent performance of the scheme during a system event.

The TBM is the overarching maintenance process of which the other types are subsets. Unlike TBM, PBM intervals are adjusted based on good or bad experiences. The CBM verification intervals can be hours, or even milliseconds between non-disruptive self-monitoring checks within or around components as they remain in service.

TBM, PBM, and CBM can be combined for individual components, or within a complete Protection System. The following diagram illustrates the relationship between various types of maintenance practices described in this section. In the Venn diagram, the overlapping regions show the relationship of TBM with PBM historical information and the inherent continuous monitoring offered through CBM.

This figure shows:

- Region 1: The TBM intervals that are increased based on known reported operational condition of individual components that are monitoring themselves.
- Region 2: The TBM intervals that are adjusted up or down based on results of analysis of maintenance history of statistically significant population of similar products that have been subject to TBM.
- Region 3: Optimal TBM intervals based on regions 1 and 2.



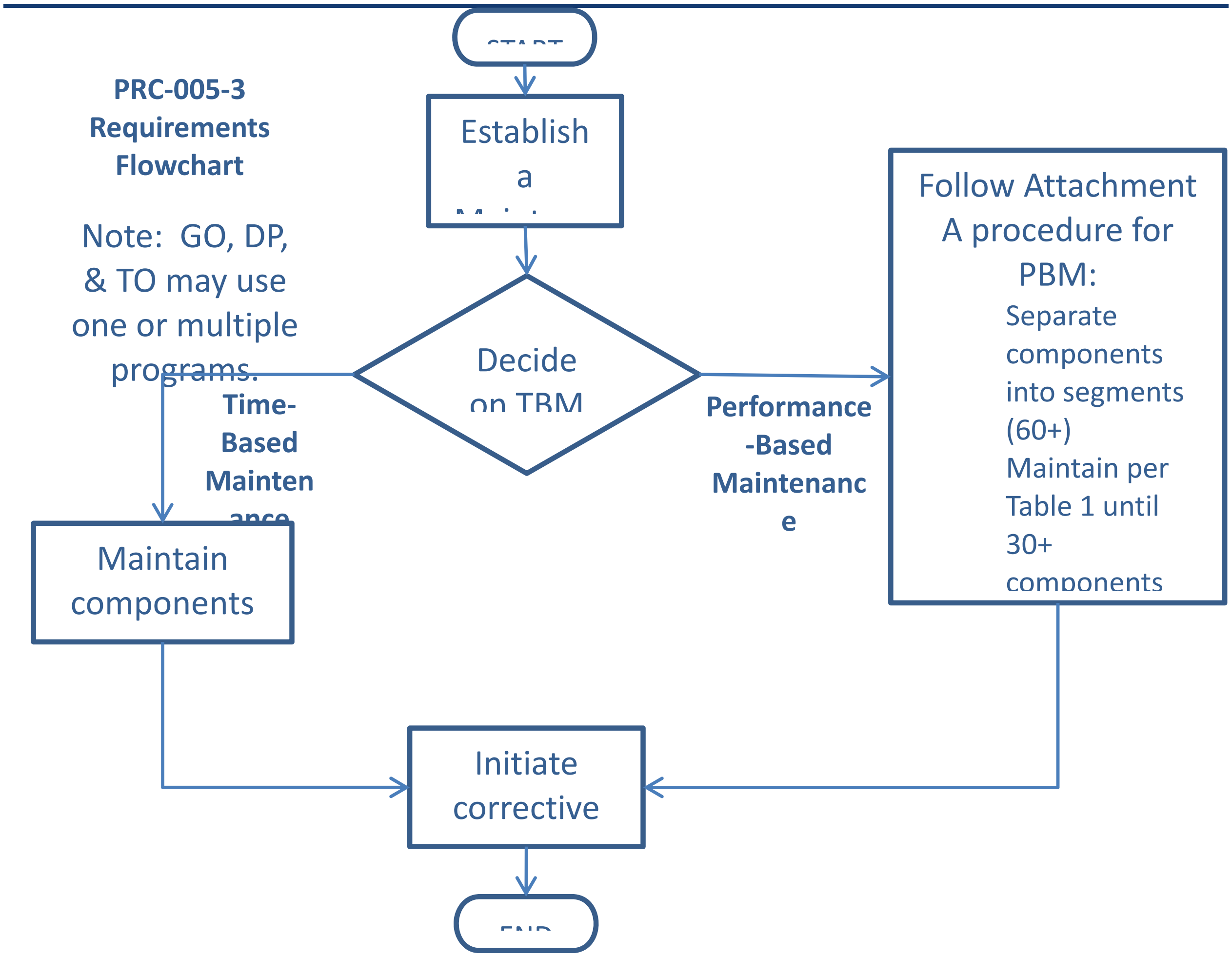
Relationship of time-based maintenance types

5.1.1 Frequently Asked Questions:

The standard seems very complicated, and is difficult to understand. Can it be simplified?

Because the standard is establishing parameters for condition-based Maintenance (R1) and Performance-Based Maintenance (R2), in addition to simple time-based Maintenance, it does appear to be complicated. At its simplest, an entity needs to ONLY perform time-based maintenance according to the unmonitored rows of the Tables. If an entity then wishes to take advantage of monitoring on its Protection System components and its available lengthened time intervals, then it may, as long as the component has the listed monitoring attributes. If an entity wishes to use historical performance of its Protection System components to perform Performance-Based Maintenance, then R2 applies.

Please see the following diagram, which provides a "flow chart" of the standard.



We have an electromechanical (unmonitored) relay that has a trip output to a lockout relay (unmonitored) which trips our transformer off-line by tripping the transformer's high-side and low-side circuit breakers. What testing must be done for this system?

This system is made up of components that are all unmonitored. Assuming a time-based Protection System Maintenance Program schedule (as opposed to a Performance-Based maintenance program), each component must be maintained per the most frequent hands-on activities listed in the Tables.

5.2 Extending Time-Based Maintenance

All maintenance is fundamentally time-based. Default time-based intervals are commonly established to assure proper functioning of each component of the Protection System, when data on the reliability of the components is not available other than observations from time-based maintenance. The following factors may influence the established default intervals:

- If continuous indication of the functional condition of a component is available (from relays or chargers or any self-monitoring device), then the intervals may be extended, or manual testing may be eliminated. This is referred to as condition-based maintenance or CBM. CBM is valid only for precisely the components subject to monitoring. In the case of microprocessor-based relays, self-monitoring may not include automated diagnostics of every component within a microprocessor.

- Previous maintenance history for a group of components of a common type may indicate that the maintenance intervals can be extended, while still achieving the desired level of performance. This is referred to as Performance-Based Maintenance, or PBM. It is also sometimes referred to as reliability-centered maintenance, or RCM; but PBM is used in this document.
- Observed proper operation of a component may be regarded as a maintenance verification of the respective component or element in a microprocessor-based device. For such an observation, the maintenance interval may be reset only to the degree that can be verified by data available on the operation. For example, the trip of an electromechanical relay for a Fault verifies the trip contact and trip path, but only through the relays in series that actually operated; one operation of this relay cannot verify correct calibration.

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. The improper application of test signals may cause failure of a component. For example, in electromechanical overcurrent relays, test currents have been known to destroy convolution springs.

In addition, maintenance usually takes the component out of service, during which time it is not able to perform its function. Cutout switch failures, or failure to restore switch position, commonly lead to protection failures.

5.2.1 Frequently Asked Questions:

If I show the protective device out of service while it is being repaired, then can I add it back as a new protective device when it returns? If not, my relay testing history would show that I was out of compliance for the last maintenance cycle.

The maintenance and testing requirements (R5) (in essence) state "…shall demonstrate efforts to correct any identified Unresolved Maintenance Issues." The type of corrective activity is not stated; however it could include repairs or replacements.

Your documentation requirements will increase, of course, to demonstrate that your device tested bad and had corrective actions initiated. Your regional entity could very well ask for documentation showing status of your corrective actions.

6. Condition-Based Maintenance (CBM) Programs

Condition-based maintenance is the process of gathering and monitoring the information available from modern microprocessor-based relays and other intelligent electronic devices (IEDs) that monitor Protection System or Automatic Reclosing elements. These devices generate monitoring information during normal operation, and the information can be assessed at a convenient location remote from the substation. The information from these relays and IEDs is divided into two basic types:

1. Information can come from background self-monitoring processes, programmed by the manufacturer, or by the user in device logic settings. The results are presented by alarm contacts or points, front panel indications, and by data communications messages.
2. Information can come from event logs, captured files, and/or oscillographic records for Faults and Disturbances, metered values, and binary input status reports. Some of these are available on the device front panel display, but may be available via data communications ports. Large files of Fault information can only be retrieved via data communications. These results comprise a mass of data that must be further analyzed for evidence of the operational condition of the Protection System.

Using these two types of information, the user can develop an effective maintenance program carried out mostly from a central location remote from the substation. This approach offers the following advantages:

Non-invasive Maintenance: The system is kept in its normal operating state, without human intervention for checking. This reduces risk of damage, or risk of leaving the system in an inoperable state after a manual test. Experience has shown that keeping human hands away from equipment known to be working correctly enhances reliability.

Virtually Continuous Monitoring: CBM will report many hardware failure problems for repair within seconds or minutes of when they happen. This reduces the percentage of problems that are discovered through incorrect relaying performance. By contrast, a hardware failure discovered by TBM may have been there for much of the time interval between tests, and there is a good chance that some devices will show health problems by incorrect operation before being caught in the next test round. The frequent or continuous nature of CBM makes the effective verification interval far shorter than any required TBM maximum interval. To use the extended time intervals available through Condition Based Maintenance, simply look for the rows in the Tables that refer to monitored items.

6.1 Frequently Asked Questions:

My microprocessor relays and dc circuit alarms are contained on relay panels in a 24-hour attended control room. Does this qualify as an extended time interval condition-based (monitored) system?

Yes, provided the station attendant (plant operator, etc.) monitors the alarms and other indications (comparable to the monitoring attributes) and reports them within the given time limits that are stated in the criteria of the Tables.

When documenting the basis for inclusion of components into the appropriate levels of monitoring, as per Requirement R1 (Part 1.4) of the standard, is it necessary to

provide this documentation about the device by listing of every component and the specific monitoring attributes of each device?

No. While maintaining this documentation on the device level would certainly be permissible, it is not necessary. Global statements can be made to document appropriate levels of monitoring for the entire population of a component type or portion thereof.

For example, it would be permissible to document the conclusion that all BES substation dc supply battery chargers are monitored by stating the following within the program description:

> "All substation dc supply battery chargers are considered monitored and subject to the rows for monitored equipment of Table 1-4 requirements, as all substation dc supply battery chargers are equipped with dc voltage alarms and ground detection alarms that are sent to the manned control center."

Similarly, it would be acceptable to use a combination of a global statement and a device-level list of exclusions. Example:

> "Except as noted below, all substation dc supply battery chargers are considered monitored and subject to the rows for monitored equipment of Table 1-4 requirements, as all substation dc supply battery chargers are equipped with dc voltage alarms and ground detection alarms that are sent to the manned control center. The dc supply battery chargers of Substation X, Substation Y, and Substation Z are considered unmonitored and subject to the rows for unmonitored equipment in Table 1-4 requirements, as they are not equipped with ground detection capability."

Regardless whether this documentation is provided by device listing of monitoring attributes, by global statements of the monitoring attributes of an entire population of component types, or by some combination of these methods, it should be noted that auditors may request supporting drawings or other documentation necessary to validate the inclusion of the device(s) within the appropriate level of monitoring. This supporting background information need not be maintained within the program document structure, but should be retrievable if requested by an auditor.

7. Time-Based Versus Condition-Based Maintenance

Time-based and condition-based (or monitored) maintenance programs are both acceptable, if implemented according to technically sound requirements. Practical programs can employ a *combination of time-based and condition-based maintenance.* The standard requirements introduce the concept of optionally using condition monitoring as a documented element of a maintenance program.

The Federal Energy Regulatory Commission (FERC), in its Order Number 693 Final Rule, dated March 16, 2007 (18 CFR Part 40, Docket No. RM06-16-000) on Mandatory Reliability Standards for the Bulk-Power System, directed NERC to submit a modification to PRC-005-1b that includes a requirement that maintenance and testing of a Protection System must be carried out within a maximum allowable interval that is appropriate to the type of the Protection System and its impact on the reliability of the Bulk Power System. Accordingly, this Supplementary Reference Paper refers to the specific maximum allowable intervals in PRC-005-4~~3~~. The defined time limits allow for longer time intervals if the maintained component is monitored.

A key feature of condition-based monitoring is that it effectively reduces the time delay between the moment of a protection failure and time the Protection System or Automatic Reclosing owner knows about it, for the monitored segments of the Protection System. In some cases, the verification is practically continuous - the time interval between verifications is minutes or seconds. Thus, technically sound, condition-based verification, meets the verification requirements of the FERC order even more effectively than the strictly time-based tests of the same system components.

The result is that:

This NERC standard permits utilities to use a technically sound approach and to take advantage of remote monitoring, data analysis, and control capabilities of modern Protection System and Automatic Reclosing Components to reduce the need for periodic site visits and invasive testing of components by on-site technicians. This periodic testing must be conducted within the maximum time intervals specified in the Tables of PRC-005-4~~3~~.

7.1 Frequently Asked Questions:

What is a Calendar Year?

Calendar Year - January 1 through December 31 of any year. As an example, if an event occurred on June 17, 2009 and is on a “One Calendar Year Interval,” the next event would have to occur on or before December 31, 2010.

Please provide an example of “4 Calendar Months”.

If a maintenance activity is described as being needed every four Calendar Months then it is performed in a (given) month and due again four months later. For example a battery bank is inspected in month number 1 then it is due again before the end of the month number5. And specifically consider that you perform your battery inspection on January 3, 2010 then it must be inspected again before the end of May. Another example could be that a four-month inspection was performed in January is due in May, but if performed in March (instead of May) would still be due four months later therefore the activity is due again July. Basically every “four Calendar Months” means to add four months from the last time the activity was performed.

Please provide an example of the unmonitored versus other levels of monitoring available?

An unmonitored Protection System has no monitoring and alarm circuits on the Protection System components. A Protection System component that has monitoring attributes but no alarm output connected is considered to be unmonitored.

A monitored Protection System or an individual monitored component of a Protection System has monitoring and alarm circuits on the Protection System components. The alarm circuits must alert, within 24 hours, a location wherein corrective action can be initiated. This location might be, but is not limited to, an Operations Center, Dispatch Office, Maintenance Center or even a portable SCADA system.

There can be a combination of monitored and unmonitored Protection Systems within any given scheme, substation or plant; there can also be a combination of monitored and unmonitored components within any given Protection System.

Example #1: A combination of monitored and unmonitored components within a given Protection System might be:

- A microprocessor relay with an internal alarm connected to SCADA to alert 24-hr staffed operations center; it has internal self diagnosis and alarming. (monitored)
- Instrumentation transformers, with no monitoring, connected as inputs to that relay. (unmonitored)
- A vented Lead-Acid battery with a low voltage alarm for the station dc supply voltage and an unintentional grounds detection alarm connected to SCADA. (monitoring varies)
- A circuit breaker with a trip coil, and the trip circuit is not monitored. (unmonitored)

Given the particular components and conditions, and using Table 1 and Table 2, the particular components have maximum activity intervals of:

<u>Every four calendar months</u>, inspect:

- Electrolyte level (station dc supply voltage and unintentional ground detection is being maintained more frequently by the monitoring system).

<u>Every 18 calendar months</u>, verify/inspect the following:

- Battery bank ohmic values to station battery baseline (if performance tests are not opted)
- Battery charger float voltage
- Battery rack integrity
- Cell condition of all individual battery cells (where visible)
- Battery continuity
- Battery terminal connection resistance
- Battery cell-to-cell resistance (where available to measure)

Every six calendar years, perform/verify the following:

- Battery performance test (if internal ohmic tests or other measurements indicative of battery performance are not opted)
- Verify that each trip coil is able to operate the circuit breaker, interrupting device, or mitigating device
- For electromechanical lock-out relays, electrical operation of electromechanical trip

Every 12 calendar years, verify the following:

- Microprocessor relay settings are as specified
- Operation of the microprocessor's relay inputs and outputs that are essential to proper functioning of the Protection System
- Acceptable measurement of power System input values seen by the microprocessor protective relay
- Verify that current and voltage signal values are provided to the protective relays
- Protection System component monitoring for the battery system signals are conveyed to a location where corrective action can be initiated
- The microprocessor relay alarm signals are conveyed to a location where corrective action can be initiated
- Verify all trip paths in the control circuitry associated with protective functions through the trip coil(s) of the circuit breakers or other interrupting devices
- Auxiliary outputs that are in the trip path shall be maintained as detailed in Table 1-5 of the standard under the 'Unmonitored Control Circuitry Associated with Protective Functions" section'
- Auxiliary outputs not in a trip path (i.e., annunciation or DME input) are not required, by this standard, to be checked

Example #2: A combination of monitored and unmonitored components within a given Protection System might be:

- A microprocessor relay with integral alarm that is not connected to SCADA. (unmonitored)
- Current and voltage signal values, with no monitoring, connected as inputs to that relay. (unmonitored)
- A vented lead-acid battery with a low voltage alarm for the station dc supply voltage and an unintentional grounds detection alarm connected to SCADA. (monitoring varies)
- A circuit breaker with a trip coil, with no circuits monitored. (unmonitored)

Given the particular components and conditions, and using the Table 1 (Maximum Allowable Testing Intervals and Maintenance Activities) and Table 2 (Alarming Paths and Monitoring), the particular components have maximum activity intervals of:

Every four calendar months, inspect:

- Electrolyte level (station dc supply voltage and unintentional ground detection is being maintained more frequently by the monitoring system)

Every 18 calendar months, verify/inspect the following:

- Battery bank trending of ohmic values or other measurements indicative of battery performance to station battery baseline (if performance tests are not opted)
- Battery charger float voltage
- Battery rack integrity
- Cell condition of all individual battery cells (where visible)
- Battery continuity
- Battery terminal connection resistance
- Battery cell-to-cell resistance (where available to measure)

Every six calendar years, verify/perform the following:

- Verify operation of the relay inputs and outputs that are essential to proper functioning of the Protection System
- Verify acceptable measurement of power system input values as seen by the relays
- Verify that each trip coil is able to operate the circuit breaker, interrupting device, or mitigating device
- For electromechanical lock-out relays, electrical operation of electromechanical trip
- Battery performance test (if internal ohmic tests are not opted)

Every 12 calendar years, verify the following:

- Current and voltage signal values are provided to the protective relays
- Protection System component monitoring for the battery system signals are conveyed to a location where corrective action can be initiated
- All trip paths in the control circuitry associated with protective functions through the trip coil(s) of the circuit breakers or other interrupting devices
- Auxiliary outputs that are in the trip path shall be maintained, as detailed in Table 1-5 of the standard under the Unmonitored Control Circuitry Associated with Protective Functions" section
- Auxiliary outputs not in a trip path (i.e., annunciation or DME input) are not required, by this standard, to be checked

Example #3: A combination of monitored and unmonitored components within a given Protection System might be:

- A microprocessor relay with alarm connected to SCADA to alert 24-hr staffed operations center; it has internal self diagnosis and alarms. (monitored)
- Current and voltage signal values, with monitoring, connected as inputs to that relay (monitored)
- Vented Lead-Acid battery without any alarms connected to SCADA (unmonitored)
- Circuit breaker with a trip coil, with no circuits monitored (unmonitored)

Given the particular components, conditions, and using the Table 1 (Maximum Allowable Testing Intervals and Maintenance Activities) and Table 2 (Alarming Paths and Monitoring), the particular components shall have maximum activity intervals of:

<u>Every four calendar months</u>, verify/inspect the following:

- Station dc supply voltage
- For unintentional grounds
- Electrolyte level

<u>Every 18 calendar months</u>, verify/inspect the following:

- Battery bank trending of ohmic values or other measurements indicative of battery performance to station battery baseline (if performance tests are not opted)
- Battery charger float voltage
- Battery rack integrity
- Battery continuity
- Battery terminal connection resistance
- Battery cell-to-cell resistance (where available to measure)
- Condition of all individual battery cells (where visible)

<u>Every six calendar years</u>, perform/verify the following:

- Battery performance test (if internal ohmic tests or other measurements indicative of battery performance are not opted)
- Verify that each trip coil is able to operate the circuit breaker, interrupting device, or mitigating device
- For electromechanical lock-out relays, electrical operation of electromechanical trip

<u>Every 12 calendar years</u>, verify the following:

- The microprocessor relay alarm signals are conveyed to a location where corrective action can be taken
- Microprocessor relay settings are as specified
- Operation of the microprocessor’s relay inputs and outputs that are essential to proper functioning of the Protection System
- Acceptable measurement of power system input values seen by the microprocessor protective relay
- Verify all trip paths in the control circuitry associated with protective functions through the trip coil(s) of the circuit breakers or other interrupting devices
- Auxiliary outputs that are in the trip path shall be maintained, as detailed in Table 1-5 of the standard under the Unmonitored Control Circuitry Associated with Protective Functions section
- Auxiliary outputs not in a trip path (i.e. annunciation or DME input) are not required, by this standard, to be checked

Why do components have different maintenance activities and intervals if they are monitored?

The intent behind different activities and intervals for monitored equipment is to allow less frequent manual intervention when more information is known about the condition of Protection System components. Condition-Based Maintenance is a valuable asset to improve reliability.

Can all components in a Protection System be monitored?

No. For some components in a Protection System, monitoring will not be relevant. For example, a battery will always need some kind of inspection.

We have a 30-year-old oil circuit breaker with a red indicating lamp on the substation relay panel that is illuminated only if there is continuity through the breaker trip coil. There is no SCADA monitor or relay monitor of this trip coil. The line protection relay package that trips this circuit breaker is a microprocessor relay that has an integral alarm relay that will assert on a number of conditions that includes a loss of power to the relay. This alarm contact connects to our SCADA system and alerts our 24-hour operations center of relay trouble when the alarm contact closes. This microprocessor relay trips the circuit breaker only and does not monitor trip coil continuity or other things such as trip current. Are the components monitored or not? How often must I perform maintenance?

The protective relay is monitored and can be maintained every 12 years, or when an Unresolved Maintenance Issue arises. The control circuitry can be maintained every 12 years. The circuit breaker trip coil(s) has to be electrically operated at least once every six years.

What is a mitigating device?

A mitigating device is the device that acts to respond as directed by a Special Protection System. It may be a breaker, valve, distributed control system, or any variety of other devices. This response may include tripping, closing, or other control actions.

8. Maximum Allowable Verification Intervals

The maximum allowable testing intervals and maintenance activities show how CBM with newer device types can reduce the need for many of the tests and site visits that older Protection System components require. As explained below, there are some sections of the Protection System that monitoring or data analysis may not verify. Verifying these sections of the Protection System or Automatic Reclosing requires some persistent TBM activity in the maintenance program. However, some of this TBM can be carried out remotely - for example, exercising a circuit breaker through the relay tripping circuits using the relay remote control capabilities can be used to verify function of one tripping path and proper trip coil operation, if there has been no Fault or routine operation to demonstrate performance of relay tripping circuits.

8.1 Maintenance Tests

Periodic maintenance testing is performed to ensure that the protection and control system is operating correctly after a time period of field installation. These tests may be used to ensure that individual components are still operating within acceptable performance parameters - this type of test is needed for components susceptible to degraded or changing characteristics due to aging and wear. Full system performance tests may be used to confirm that the total Protection System functions from measurement of power system values, to properly identifying Fault characteristics, to the operation of the interrupting devices.

8.1.1 Table of Maximum Allowable Verification Intervals

Table 1 (collectively known as Table 1, individually called out as Tables 1-1 through 1-5), Table 2, Table 3,~~ and~~ Table 4~~-~~-1 through Table4-2 and Table 5 in the standard specify maximum allowable verification intervals for various generations of Protection Systems~~, and~~ Automatic Reclosing and Sudden Pressure Relaying and categories of equipment that comprise these systems. The right column indicates maintenance activities required for each category.

The types of components are illustrated in Figures 1 and 2 at the end of this paper. Figure 1 shows an example of telecommunications-assisted transmission Protection System comprising substation equipment at each terminal and a telecommunications channel for relaying between the two substations. Figure 2 shows an example of a generation Protection System. The various sub-systems of a Protection System that need to be verified are shown.

Non-distributed UFLS, UVLS, and SPS are additional categories of Table 1 that are not illustrated in these figures. Non-distributed UFLS, UVLS and SPS all use identical equipment as Protection Systems in the performance of their functions; and, therefore, have the same maintenance needs.

Distributed UFLS and UVLS Systems, which use local sensing on the distribution System and trip co-located non-BES interrupting devices, are addressed in Table 3 with reduced maintenance activities.

While it is easy to associate protective relays to multiple levels of monitoring, it is also true that most of the components that can make up a Protection System can also have technological advancements that place them into higher levels of monitoring.

To use the Maintenance Activities and Intervals Tables from ~~PRC-005-3~~PRC-005-4:

- First find the Table associated with your component. The tables are arranged in the order of mention in the definition of Protection System;
  - Table 1-1 is for protective relays,
  - Table 1-2 is for the associated communications systems,
  - Table 1-3 is for current and voltage sensing devices,
  - Table 1-4 is for station dc supply and
  - Table 1-5 is for control circuits.
  - Table 2, is for alarms; this was broken out to simplify the other tables.
  - Table 3 is for components which make-up distributed UFLS and UVLS Systems.
  - Table 4 is for Automatic Reclosing.
  - Table 5 is for Sudden Pressure Relaying.
- Next look within that table for your device and its degree of monitoring. The Tables have different hands-on maintenance activities prescribed depending upon the degree to which you monitor your equipment. Find the maintenance activity that applies to the monitoring level that you have on your piece of equipment.
- This Maintenance activity is the minimum maintenance activity that must be documented.
- If your Performance-Based Maintenance (PBM) plan requires more activities, then you must perform and document to this higher standard. (Note that this does not apply unless you utilize PBM.)
- After the maintenance activity is known, check the maximum maintenance interval; this time is the maximum time allowed between hands-on maintenance activity cycles of this component.
- If your Performance-Based Maintenance plan requires activities more often than the Tables maximum, then you must perform and document those activities to your more stringent standard. (Note that this does not apply unless you utilize PBM.)
- Any given component of a Protection System can be determined to have a degree of monitoring that may be different from another component within that same Protection System. For example, in a given Protection System it is possible for an entity to have a monitored protective relay and an unmonitored associated communications system; this combination would require hands-on maintenance activity on the relay at least once every 12 years and attention paid to the communications system as often as every four months.
- An entity does not have to utilize the extended time intervals made available by this use of condition-based monitoring. An easy choice to make is to simply utilize the unmonitored level of maintenance made available in each of the Tables. While the maintenance activities resulting from this choice would require more maintenance man-hours, the maintenance requirements may be simpler to document and the resulting maintenance plans may be easier to create.

For each Protection System Component, Table 1 shows maximum allowable testing intervals for the various degrees of monitoring. For each Automatic Reclosing Component, Table 4 shows maximum allowable testing intervals for the various degrees of monitoring. These degrees of monitoring, or levels, range from the legacy unmonitored through a system that is more comprehensively monitored.

It has been noted here that an entity may have a PSMP that is more stringent than ~~PRC-005-3~~PRC-005-4. There may be any number of reasons that an entity chooses a more stringent plan than the minimums prescribed within ~~PRC-005-3~~PRC-005-4, most notable of which is an entity using performance based maintenance methodology. If an entity has a Performance-Based Maintenance program, then that plan must be followed, even if the plan proves to be more stringent than the minimums laid out in the Tables.

8.1.2 Additional Notes for Tables 1-1 through 1-5, Table 3, and Table 4

1. For electromechanical relays, adjustment is required to bring measurement accuracy within the tolerance needed by the asset owner. Microprocessor relays with no remote monitoring of alarm contacts, etc, are unmonitored relays and need to be verified within the Table interval as other unmonitored relays but may be verified as functional by means other than testing by simulated inputs.

2. Microprocessor relays typically are specified by manufacturers as not requiring calibration, but acceptable measurement of power system input values must be verified (verification of the Analog to Digital [A/D] converters) within the Table intervals. The integrity of the digital inputs and outputs that are used as protective functions must be verified within the Table intervals.

3. Any Phasor Measurement Unit (PMU) function whose output is used in a Protection System or SPS (as opposed to a monitoring task) must be verified as a component in a Protection System.

4. In addition to verifying the circuitry that supplies dc to the Protection System, the owner must maintain the station dc supply. The most widespread station dc supply is the station battery and charger. Unlike most Protection System components, physical inspection of station batteries for signs of component failure, reduced performance, and degradation are required to ensure that the station battery is reliable enough to deliver dc power when required. IEEE Standards 450, 1188, and 1106 for vented lead-acid, valve-regulated lead-acid, and nickel-cadmium batteries, respectively (which are the most commonly used substation batteries on the NERC BES) have been developed as an important reference source of maintenance recommendations. The Protection System owner might want to follow the guidelines in the applicable IEEE recommended practices for battery maintenance and testing, especially if the battery in question is used for application requirements in addition to the protection and control demands covered under this standard. However, the Standard Drafting Team has tailored the battery maintenance and testing guidelines in ~~PRC-005-3~~PRC-005-4 for the Protection System owner which are application specific for the BES Facilities. While the IEEE recommendations are all encompassing, ~~PRC-005-3~~PRC-005-4 is a more economical approach while addressing the reliability requirements of the BES.

5. Aggregated small entities might distribute the testing of the population of UFLS/UVLS systems, and large entities will usually maintain a portion of these systems in any given

year. Additionally, if relatively small quantities of such systems do not perform properly, it will not affect the integrity of the overall program. Thus, these distributed systems have decreased requirements as compared to other Protection Systems.

6. Voltage & current sensing device circuit input connections to the Protection System relays can be verified by (but not limited to) comparison of measured values on live circuits or by using test currents and voltages on equipment out of service for maintenance. The verification process can be automated or manual. The values should be verified to be as expected (phase value and phase relationships are both equally important to verify).
7. "End-to-end test," as used in this Supplementary Reference, is any testing procedure that creates a remote input to the local communications-assisted trip scheme. While this can be interpreted as a GPS-type functional test, it is not limited to testing via GPS. Any remote scheme manipulation that can cause action at the local trip path can be used to functionally-test the dc control circuitry. A documented Real-time trip of any given trip path is acceptable in lieu of a functional trip test. It is possible, with sufficient monitoring, to be able to verify each and every parallel trip path that participated in any given dc control circuit trip. Or another possible solution is that a single trip path from a single monitored relay can be verified to be the trip path that successfully tripped during a Real-time operation. The variations are only limited by the degree of engineering and monitoring that an entity desires to pursue.
8. A/D verification may use relay front panel value displays, or values gathered via data communications. Groupings of other measurements (such as vector summation of bus feeder currents) can be used for comparison if calibration requirements assure acceptable measurement of power system input values.
9. Notes 1-8 attempt to describe some testing activities; they do not represent the only methods to achieve these activities, but rather some possible methods. Technological advances, ingenuity and/or industry accepted techniques can all be used to satisfy maintenance activity requirements; the standard is technology- and method-neutral in most cases.

8.1.3 Frequently Asked Questions:

What is meant by "Verify that settings are as specified" maintenance activity in Table 1-1?

Verification of settings is an activity directed mostly towards microprocessor- based relays. For relay maintenance departments that choose to test microprocessor-based relays in the same manner as electromechanical relays are tested, the testing process sometimes requires that some specific functions be disabled. Later tests might enable the functions previously disabled, but perhaps still other functions or logic statements were then masked out. It is imperative that, when the relay is placed into service, the settings in the relay be the settings that were intended to be in that relay or as the standard states "…settings are as specified."

Many of the microprocessor- based relays available today have software tools which provide this functionality and generate reports for this purpose.

For evidence or documentation of this requirement, a simple recorded acknowledgement that the settings were checked to be as specified is sufficient.

The drafting team was careful not to require "…that the relay settings be correct…" because it was believed that this might then place a burden of proof that the specified settings would result in the correct intended operation of the interrupting device. While that is a noble intention, the measurable proof of such a requirement is immense. The intent is that settings of the component be as specified at the conclusion of maintenance activities, whether those settings may have "drifted" since the prior maintenance or whether changes were made as part of the testing process.

Are electromechanical relays included in the "Verify that settings are as specified" maintenance activity in Table 1-1?

Verification of settings is an activity directed towards the application of protection related functions of microprocessor based relays. Electromechanical relays require calibration verification by voltage and/or current injection; and, thus, the settings are verified during calibration activity. In the example of a time-overcurrent relay, a minor deviation in time dial, versus the settings, may be acceptable, as long as the relay calibration is within accepted tolerances at the injected current amplitudes. A major deviation may require further investigation, as it could indicate a problem with the relay or an incorrect relay style for the application.

The verification of phase current and voltage measurements by comparison to other quantities seems reasonable. How, though, can I verify residual or neutral currents, or 3V0 voltages, by comparison, when my system is closely balanced?

Since these inputs are verified at commissioning, maintenance verification requires ensuring that phase quantities are as expected and that 3IO and 3VO quantities appear equal to or close to 0.

These quantities also may be verified by use of oscillographic records for connected microprocessor relays as recorded during system Disturbances. Such records may compare to similar values recorded at other locations by other microprocessor relays for the same event, or compared to expected values (from short circuit studies) for known Fault locations.

What does this Standard require for testing an auxiliary tripping relay?

Table 1 and Table 3 requires that a trip test must verify that the auxiliary tripping relay(s) and/or lockout relay(s) which are directly in a trip path from the protective relay to the interrupting device trip coil operate(s) electrically. Auxiliary outputs not in a trip path (i.e. annunciation or DME input) are not required, by this standard, to be checked.

Do I have to perform a full end-to-end test of a Special Protection System?

No. All portions of the SPS need to be maintained, and the portions must overlap, but the overall SPS does not need to have a single end-to-end test. In other words it may be tested in piecemeal fashion provided all of the pieces are verified.

What about SPS interfaces between different entities or owners?

As in all of the Protection System requirements, SPS segments can be tested individually, thus minimizing the need to accommodate complex maintenance schedules.

What do I have to do if I am using a phasor measurement unit (PMU) as part of a Protection System or Special Protection System?

Any Phasor Measurement Unit (PMU) function whose output is used in a Protection System or Special Protection System (as opposed to a monitoring task) must be verified as a component in a Protection System.

How do I maintain a Special Protection System or relay sensing for non-distributed UFLS or UVLS Systems?

Since components of the SPS, UFLS and UVLS are the same types of components as those in Protection Systems, then these components should be maintained like similar components used for other Protection System functions. In many cases the devices for SPS, UFLS and UVLS are also used for other protective functions. The same maintenance activities apply with the exception that distributed systems (UFLS and UVLS) have fewer dc supply and control circuitry maintenance activity requirements.

For the testing of the output action, verification may be by breaker tripping, but may be verified in overlapping segments. For example, an SPS that trips a remote circuit breaker might be tested by testing the various parts of the scheme in overlapping segments. Another method is to document the Real-time tripping of an SPS scheme should that occur. Forced trip tests of circuit breakers (etc) that are a part of distributed UFLS or UVLS schemes are not required.

The established maximum allowable intervals do not align well with the scheduled outages for my power plant. Can I extend the maintenance to the next scheduled outage following the established maximum interval?

No. You must complete your maintenance within the established maximum allowable intervals in order to be compliant. You will need to schedule your maintenance during available outages to complete your maintenance as required, even if it means that you may do protective relay maintenance more frequently than the maximum allowable intervals. The maintenance intervals were selected with typical plant outages, among other things, in mind.

If I am unable to complete the maintenance, as required, due to a major natural disaster (hurricane, earthquake, etc.), how will this affect my compliance with this standard?

The Sanction Guidelines of the North American Electric Reliability Corporation, effective January 15, 2008, provides that the Compliance Monitor will consider extenuating circumstances when considering any sanctions.

What if my observed testing results show a high incidence of out-of-tolerance relays; or, even worse, I am experiencing numerous relay Misoperations due to the relays being out-of-tolerance?

The established maximum time intervals are mandatory only as a not-to-exceed limitation. The establishment of a maximum is measurable. But any entity can choose to test some or all of their Protection System components more frequently (or to express it differently, exceed the minimum requirements of the standard). Particularly if you find that the maximum intervals in the standard do not achieve your expected level of performance, it is understandable that you would maintain the related equipment more frequently. A high incidence of relay Misoperations is in no one's best interest.

We believe that the four-month interval between inspections is unneccessary. Why can we not perform these inspections twice per year?

The Standard Drafting Team, through the comment process, has discovered that routine monthly inspections are not the norm. To align routine station inspections with other important inspections, the four-month interval was chosen. In lieu of station visits, many activities can be accomplished with automated monitoring and alarming.

Our maintenance plan calls for us to perform routine protective relay tests every 3 years. If we are unable to achieve this schedule, but we are able to complete the procedures in less than the maximum time interval ,then are we in or out of compliance?

According to R3, if you have a time-based maintenance program, then you will be in violation of the standard only if you exceed the maximum maintenance intervals prescribed in the Tables. According to R4, if your device in question is part of a Performance-Based Maintenance program, then you will be in violation of the standard if you fail to meet your PSMP, even if you do not exceed the maximum maintenance intervals prescribed in the Tables. The intervals in the Tables are associated with TBM and CBM; Attachment A is associated with PBM.

Please provide a sample list of devices or systems that must be verified in a generator, generator step-up transformer, generator connected station service or generator connected excitation transformer to meet the requirements of this maintenance standard.

Examples of typical devices and systems that may directly trip the generator, or trip through a lockout relay, may include, but are not necessarily limited to:

- Fault protective functions, including distance functions, voltage-restrained overcurrent functions, or voltage-controlled overcurrent functions
- Loss-of-field relays
- Volts-per-hertz relays
- Negative sequence overcurrent relays
- Over voltage and under voltage protection relays
- Stator-ground relays
- Communications-based Protection Systems such as transfer-trip systems
- Generator differential relays
- Reverse power relays
- Frequency relays
- Out-of-step relays
- Inadvertent energization protection
- Breaker failure protection

For generator step-up, generator-connected station service transformers, or generator connected excitation transformers, operation of any of the following associated protective relays frequently would result in a trip of the generating unit; and, as such, would be included in the program:

- Transformer differential relays

- Neutral overcurrent relay
- Phase overcurrent relays

Relays which trip breakers serving station auxiliary Loads such as pumps, fans, or fuel handling equipment, etc., need not be included in the program, even if the loss of the those Loads could result in a trip of the generating unit. Furthermore, relays which provide protection to secondary unit substation (SUS) or low switchgear transformers and relays protecting other downstream plant electrical distribution system components are not included in the scope of this program, even if a trip of these devices might eventually result in a trip of the generating unit. For example, a thermal overcurrent trip on the motor of a coal-conveyor belt could eventually lead to the tripping of the generator, but it does not cause the trip.

In the case where a plant does not have a generator connected station service transformer such that it is normally fed from a system connected station service transformer, is it still the drafting team's intent to exclude the Protection Systems for these system connected auxiliary transformers from scope even when the loss of the normal (system connected) station service transformer will result in a trip of a BES generating Facility?

The SDT does not intend that the system-connected station service transformers be included in the Applicability. The generator-connected station service transformers and generator connected excitation transformers are often connected to the generator bus directly without an interposing breaker; thus, the Protection Systems on these transformers will trip the generator as discussed in 4.2.5.1.

What is meant by "verify operation of the relay inputs and outputs that are essential to proper functioning of the Protection System?"

Any input or output (of the relay) that "affects the tripping" of the breaker is included in the scope of I/O of the relay to be verified. By "affects the tripping," one needs to realize that sometimes there are more inputs and outputs than simply the output to the trip coil. Many important protective functions include things like breaker fail initiation, zone timer initiation and sometimes even 52a/b contact inputs are needed for a protective relay to correctly operate.

Each input should be "picked up" or "turned on and off" and verified as changing state by the microprocessor of the relay. Each output should be "operated" or "closed and opened" from the microprocessor of the relay and the output should be verified to change state on the output terminals of the relay. One possible method of testing inputs of these relays is to "jumper" the needed dc voltage to the input and verify that the relay registered the change of state.

Electromechanical lock-out relays (86) (used to convey the tripping current to the trip coils) need to be electrically operated to prove the capability of the device to change state. These tests need to be accomplished at least every six years, unless PBM methodology is applied.

The contacts on the 86 or auxiliary tripping relays (94) that change state to pass on the trip current to a breaker trip coil need only be checked every 12 years with the control circuitry.

What is the difference between a distributed UFLS/UVLS and a non-distributed UFLS/UVLS scheme?

A distributed UFLS or UVLS scheme contains individual relays which make independent Load shed decisions based on applied settings and localized voltage and/or current inputs. A distributed scheme may involve an enable/disable contact in the scheme and still be considered a distributed scheme. A non-distributed UFLS or UVLS scheme involves a system where there is some type of centralized measurement and Load shed decision being made. A non-distributed UFLS/UVLS scheme is considered similar to an SPS scheme and falls under Table 1 for maintenance activities and intervals.

8.2 Retention of Records

PRC-005-1 describes a reporting or auditing cycle of one year and retention of records for three years. However, with a three-year retention cycle, the records of verification for a Protection System might be discarded before the next verification, leaving no record of what was done if a Misoperation or failure is to be analyzed.

~~PRC-005-3~~PRC-005-4 corrects this by requiring:

The Transmission Owner, Generator Owner, and Distribution Provider shall each retain documentation of the ~~two~~ most recent performance~~s~~ of each distinct maintenance activity for the Protection System, Automatic Reclosing, or Sudden Pressure Relaying C~~c~~omponent~~s~~, or to the previous scheduled (on-site) audit date, whichever is longer.

This requirement assures that the documentation shows that the interval between maintenance cycles correctly meets the maintenance interval limits. The requirement is actually alerting the industry to documentation requirements already implemented by audit teams. Evidence of compliance bookending the interval shows interval accomplished instead of proving only your planned interval.

The SDT is aware that, in some cases, the retention period could be relatively long. But, the retention of documents simply helps to demonstrate compliance.

8.2.1 Frequently Asked Questions:

Please ~~use a specific example to demonstrate~~clarify the data retention requirements.

The data retention requirements are intended to allow the availability of maintenance records to demonstrate that the time intervals in your maintenance plan were upheld.

Maximum Maintenance Interval	Data Retention Period
4 Months, 6 Months,18 Months, or 3 Years	All activities since previous audit
6 Years	All activities since previous audit(assuming a 6 year audit cycle) or most recent performance(assuming 3 year audit cycle), whichever is longer
12 Year	All activities from the most recent performance

~~For example: "Company A" has a maintenance plan that requires its electromechanical protective relays be tested every three calendar years, with a maximum allowed grace period of an additional 18 months. This entity would be required to maintain its records of maintenance~~

~~of its last two routine scheduled tests. Thus, its test records would have a latest routine test, as well as its previous routine test. The interval between tests is, therefore, provable to an auditor as being within "Company A's" stated maximum time interval of 4.5 years.~~

~~The intent is not to require three test results proving two time intervals, but rather have two test results proving the last interval. The drafting team contends that this minimizes storage requirements, while still having minimum data available to demonstrate compliance with time intervals.~~

If an entity prefers to utilize Performance-Based Maintenance, then statistical data may well be retained for extended periods to assist with future adjustments in time intervals.

If an equipment item is replaced, then the entity can restart the maintenance-time-interval-clock if desired; however, the replacement of equipment does not remove any documentation requirements that would have been required to verify compliance with time-interval requirements. In other words, do not discard maintenance data that goes to verify your work.

The retention of documentation for new and/or replaced equipment is all about proving that the maintenance intervals had been in compliance. For example, a long-range plan of upgrades might lead an entity to ignore required maintenance; retaining the evidence of prior maintenance that existed before any retirements and upgrades proves compliance with the standard.

What does this Maintenance Standard say about commissioning? Is it necessary to have documentation in your maintenance history of the completion of commission testing?

This standard does not establish requirements for commission testing. Commission testing includes all testing activities necessary to conclude that a Facility has been built in accordance with design. While a thorough commission testing program would include, either directly or indirectly, the verification of all those Protection System attributes addressed by the maintenance activities specified in the Tables of ~~PRC-005-3~~PRC-005-4, verification of the adequacy of initial installation necessitates the performance of testing and inspections that go well beyond these routine maintenance activities. For example, commission testing might set baselines for future tests; perform acceptance tests and/or warranty tests; utilize testing methods that are not generally done routinely like staged-Fault-tests.

However, many of the Protection System attributes which are verified during commission testing are not subject to age related or service related degradation, and need not be re-verified within an ongoing maintenance program. Example – it is not necessary to re-verify correct terminal strip wiring on an ongoing basis.

~~PRC-005-3~~PRC-005-4 assumes that thorough commission testing was performed prior to a Protection System being placed in service. ~~PRC-005-3~~PRC-005-4 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.

It should be noted that commission testing frequently is performed by a different organization than that which is responsible for the ongoing maintenance of the Protection System. Furthermore, the commission testing activities will not necessarily correlate directly with the maintenance activities required by the standard. As such, it is very likely that commission testing records will deviate significantly from maintenance records in both form and content; and,

therefore, it is not necessary to maintain commission testing records within the maintenance program documentation.

Notwithstanding the differences in records, an entity would be wise to retain commissioning records to show a maintenance start date. (See below). An entity that requires that their commissioning tests have, at a minimum, the requirements of ~~PRC-005-3~~PRC-005-4 would help that entity prove time interval maximums by setting the initial time clock.

How do you determine the initial due date for maintenance?

The initial due date for maintenance should be based upon when a Protection System was tested. Alternatively, an entity may choose to use the date of completion of the commission testing of the Protection System component and the system was placed into service as the starting point in determining its first maintenance due dates. Whichever method is chosen, for newly installed Protection Systems the components should not be placed into service until minimum maintenance activities have taken place.

It is conceivable that there can be a (substantial) difference in time between the date of testing, as compared to the date placed into service. The use of the “Calendar Year” language can help determine the next due date without too much concern about being non-compliant for missing test dates by a small amount (provided your dates are not already at the end of a year). However, if there is a substantial amount of time difference between testing and in-service dates, then the testing date should be followed because it is the degradation of components that is the concern. While accuracy fluctuations may decrease when components are not energized, there are cases when degradation can take place, even though the device is not energized. Minimizing the time between commissioning tests and in-service dates will help.

If I miss two battery inspections four times out of 100 Protection System components on my transmission system, does that count as 2% or 8% when counting Violation Severity Level (VSL) for R3?

The entity failed to complete its scheduled program on two of its 100 Protection System components, which would equate to 2% for application to the VSL Table for Requirement R3. This VSL is written to compare missed components to total components. In this case two components out of 100 were missed, or 2%.

How do I achieve a “grace period” without being out of compliance?

The objective here is to create a time extension within your own PSMP that still does not violate the maximum time intervals stated in the standard. Remember that the maximum time intervals listed in the Tables cannot be extended.

For the purposes of this example, concentrating on just unmonitored protective relays – Table 1-1 specifies a maximum time interval (between the mandated maintenance activities) of six calendar years. Your plan must ensure that your unmonitored relays are tested at least once every six calendar years. You could, within your PSMP, require that your unmonitored relays be tested every four calendar years, with a maximum allowable time extension of 18 calendar months. This allows an entity to have deadlines set for the auto-generation of work orders, but still has the flexibility in scheduling complex work schedules. This also allows for that 18 calendar months to act as a buffer, in effect a grace period within your PSMP, in the event of unforeseen events. You will note that this example of a maintenance plan interval has a planned time of four years; it also has a built-in time extension allowed within the PSMP, and yet does not exceed the maximum time interval allowed by the standard. So while there are no time extensions allowed beyond the standard, an entity can still have substantial flexibility to maintain their Protection System components.

8.3 Basis for Table 1 Intervals

When developing the original _Protection System Maintenance – A Technical Reference_ in 2007, the SPCTF collected all available data from Regional Entities (REs) on time intervals recommended for maintenance and test programs. The recommendations vary widely in categorization of relays, defined maintenance actions, and time intervals, precluding development of intervals by averaging. The SPCTF also reviewed the 2005 Report [2] of the IEEE Power System Relaying Committee Working Group I-17 (Transmission Relay System Performance Comparison). Review of the I-17 report shows data from a small number of utilities, with no company identification or means of investigating the significance of particular results.

To develop a solid current base of practice, the SPCTF surveyed its members regarding their maintenance intervals for electromechanical and microprocessor relays, and asked the members to also provide definitively-known data for other entities. The survey represented 470 GW of peak Load, or 4% of the NERC peak Load. Maintenance interval averages were compiled by weighting reported intervals according to the size (based on peak Load) of the reporting utility. Thus, the averages more accurately represent practices for the large populations of Protection Systems used across the NERC regions.

The results of this survey with weighted averaging indicate maintenance intervals of five years for electromechanical or solid state relays, and seven years for unmonitored microprocessor relays.

A number of utilities have extended maintenance intervals for microprocessor relays beyond seven years, based on favorable experience with the particular products they have installed. To provide a technical basis for such extension, the SPCTF authors developed a recommendation of 10 years using the Markov modeling approach from [1], as summarized in Section 8.4. The results of this modeling depend on the completeness of self-testing or monitoring. Accordingly, this extended interval is allowed by Table 1, only when such relays are monitored as specified in the attributes of monitoring contained in Tables 1-1 through 1-5 and Table 2. Monitoring is capable of reporting Protection System health issues that are likely to affect performance within the 10 year time interval between verifications.

It is important to note that, according to modeling results, Protection System availability barely changes as the maintenance interval is varied below the 10-year mark. Thus, reducing the maintenance interval does not improve Protection System availability. With the assumptions of the model regarding how maintenance is carried out, reducing the maintenance interval actually degrades Protection System availability.

8.4 Basis for Extended Maintenance Intervals for Microprocessor Relays

Table 1 allows maximum verification intervals that are extended based on monitoring level. The industry has experience with self-monitoring microprocessor relays that leads to the Table 1 value for a monitored relay, as explained in Section 8.3. To develop a basis for the maximum interval for monitored relays in their _Protection System Maintenance – A Technical Reference_, the SPCTF used the methodology of Reference [1], which specifically addresses optimum routine maintenance intervals. The Markov modeling approach of [1] is judged to be valid for the design and typical failure modes of microprocessor relays.

The SPCTF authors ran test cases of the Markov model to calculate two key probability measures:

- Relay Unavailability - the probability that the relay is out of service due to failure or maintenance activity while the power system Element to be protected is in service.
- Abnormal Unavailability - the probability that the relay is out of service due to failure or maintenance activity when a Fault occurs, leading to failure to operate for the Fault.

The parameter in the Markov model that defines self-monitoring capability is ST (for self test). ST = 0 if there is no self-monitoring; ST = 1 for full monitoring. Practical ST values are estimated to range from .75 to .95. The SPCTF simulation runs used constants in the Markov model that were the same as those used in [1] with the following exceptions:

Sn, Normal tripping operations per hour = 21600 (reciprocal of normal Fault clearing time of 10 cycles)

Sb, Backup tripping operations per hour = 4320 (reciprocal of backup Fault clearing time of 50 cycles)

Rc, Protected component repairs per hour = 0.125 (8 hours to restore the power system)

Rt, Relay routine tests per hour = 0.125 (8 hours to test a Protection System)

Rr, Relay repairs per hour = 0.08333 (12 hours to complete a Protection System repair after failure)

Experimental runs of the model showed low sensitivity of optimum maintenance interval to these parameter adjustments.

The resulting curves for relay unavailability and abnormal unavailability versus maintenance interval showed a broad minimum (optimum maintenance interval) in the vicinity of 10 years – the curve is flat, with no significant change in either unavailability value over the range of 9, 10, or 11 years. This was true even for a relay mean time between Failures (MTBF) of 50 years, much lower than MTBF values typically published for these relays. Also, the Markov modeling indicates that both the relay unavailability and abnormal unavailability actually become higher with more frequent testing. This shows that the time spent on these more frequent tests yields no failure discoveries that approach the negative impact of removing the relays from service and running the tests.

The PSMT SDT discussed the practical need for “time-interval extensions” or “grace periods” to allow for scheduling problems that resulted from any number of business contingencies. The time interval discussions also focused on the need to reflect industry norms surrounding Generator outage frequencies. Finally, it was again noted that FERC Order 693 demanded maximum time intervals. “Maximum time intervals” by their very term negates any “time-interval extension” or “grace periods.” To recognize the need to follow industry norms on Generator outage frequencies and accommodate a form of time-interval extension, while still following FERC Order 693, the Standard Drafting Team arrived at a six-year interval for the electromechanical relay, instead of the five-year interval arrived at by the SPCTF. The PSMT SDT has followed the FERC directive for a *maximum* time interval and has determined that no extensions will be allowed. Six years has been set for the maximum time interval between manual maintenance activities. This maximum time interval also works well for maintenance cycles that have been in use in generator plants for decades.

For monitored relays, the PSMT SDT notes that the SPCTF called for 10 years as the interval between maintenance activities. This 10-year interval was chosen, even though there was "…no significant change in unavailability value over the range of 9, 10, or 11 years. This was true even for a relay Mean Time between Failures (MTBF) of 50 years…" The Standard Drafting Team again sought to align maintenance activities with known successful practices and outage schedules. The Standard does not allow extensions on any component of the Protection System; thus, the maximum allowed interval for these components has been set to 12 years. Twelve years also fits well into the traditional maintenance cycles of both substations and generator plants.

Also of note is the Table's use of the term "Calendar" in the column for "Maximum Maintenance Interval." The PSMT SDT deemed it necessary to include the term "Calendar" to facilitate annual maintenance planning, scheduling and implementation. This need is the result of known occurrences of system requirements that could cause maintenance schedules to be missed by a few days or weeks. The PSMT SDT chose the term "Calendar" to preclude the need to have schedules be met to the day. An electromechanical protective relay that is maintained in year number one need not be revisited until six years later (year number seven). For example, a relay was maintained April 10, 2008; maintenance would need to be completed no later than December 31, 2014.

Though not a requirement of this standard, to stay in line with many Compliance Enforcement Agencies audit processes an entity should define, within their own PSMP, the entity's use of terms like annual, calendar year, etc. Then, once this is within the PSMP, the entity should abide by their chosen language.

9. Performance-Based Maintenance Process

In lieu of using the Table 1 intervals, a Performance-Based Maintenance process may be used to establish maintenance intervals (*PRC-005 Attachment A Criteria for a Performance-Based Protection System Maintenance Program*). A Performance-Based Maintenance process may justify longer maintenance intervals, or require shorter intervals relative to Table 1. In order to use a Performance-Based Maintenance process, the documented maintenance program must include records of repairs, adjustments, and corrections to covered Protection Systems in order to provide historical justification for intervals, other than those established in Table 1. Furthermore, the asset owner must regularly analyze these records of corrective actions to develop a ranking of causes. Recurrent problems are to be highlighted, and remedial action plans are to be documented to mitigate or eliminate recurrent problems.

Entities with Performance-Based Maintenance track performance of Protection Systems, demonstrate how they analyze findings of performance failures and aberrations, and implement continuous improvement actions. Since no maintenance program can ever guarantee that no malfunction can possibly occur, documentation of a Performance-Based Maintenance program would serve the utility well in explaining to regulators and the public a Misoperation leading to a major System outage event.

A Performance-Based Maintenance program requires auditing processes like those included in widely used industrial quality systems (such as ***ISO 9001-2000, Quality Management Systems — Requirements;*** or applicable parts of the NIST Baldridge National Quality Program). The audits periodically evaluate:

- The completeness of the documented maintenance process
- Organizational knowledge of and adherence to the process
- Performance metrics and documentation of results
- Remediation of issues
- Demonstration of continuous improvement.

In order to opt into a Performance-Based Maintenance (PBM) program, the asset owner must first sort the various Components into population segments. Any population segment must be comprised of at least 60 individual units; if any asset owner opts for PBM, but does not own 60 units to comprise a population, then that asset owner may combine data from other asset owners until the needed 60 units is aggregated. Each population segment must be composed of a grouping of Components of a consistent design standard or particular model or type from a single manufacturer and subjected to similar environmental factors. For example: One segment cannot be comprised of both GE & Westinghouse electro-mechanical lock-out relays; likewise, one segment cannot be comprised of 60 GE lock-out relays, 30 of which are in a dirty environment, and the remaining 30 from a clean environment. This PBM process cannot be applied to batteries, but can be applied to all other Components, including (but not limited to) specific battery chargers, instrument transformers, trip coils and/or control circuitry (etc.).

9.1 Minimum Sample Size

Large Sample Size

An assumption that needs to be made when choosing a sample size is "the sampling distribution of the sample mean can be approximated by a normal probability distribution." The Central Limit Theorem states: "In selecting simple random samples of size *n* from a population, the sampling distribution of the sample mean *x* can be approximated by a normal probability distribution as the sample size becomes large." (Essentials of Statistics for Business and Economics, Anderson, Sweeney, Williams, 2003.)

To use the Central Limit Theorem in statistics, the population size should be large. The references below are supplied to help define what is large.

> "… whenever we are using a large simple random sample (rule of thumb: n>=30), the central limit theorem enables us to conclude that the sampling distribution of the sample mean can be approximated by a normal distribution." (Essentials of Statistics for Business and Economics, Anderson, Sweeney, Williams, 2003.)
>
> "If samples of size n, when n>=30, are drawn from any population with a mean *u* and a standard deviation σ, the sampling distribution of sample means approximates a normal distribution. The greater the sample size, the better the approximation." (Elementary Statistics - Picturing the World, Larson, Farber, 2003.)
>
> "The sample size is large (generally n>=30)… (Introduction to Statistics and Data Analysis - Second Edition, Peck, Olson, Devore, 2005.)
>
> "… the normal is often used as an approximation to the *t* distribution in a test of a null hypothesis about the mean of a normally distributed population when the population variance is estimated from a relatively large sample. A sample size exceeding 30 is often given as a minimal size in this connection." (Statistical Analysis for Business Decisions, Peters, Summers, 1968.)

Error of Distribution Formula

Beyond the large sample size discussion above, a sample size requirement can be estimated using the bound on the Error of Distribution Formula when the expected result is of a "Pass/Fail" format and will be between 0 and 1.0.

The Error of Distribution Formula is:

$$B = z\sqrt{\frac{\pi(1-\pi)}{n}}$$

Where:

B = bound on the error of distribution (allowable error)

z = standard error

π = expected failure rate

n = sample size required

Solving for n provides:

$$n = \pi(1-\pi)\left(\frac{z}{B}\right)^2$$

Minimum Population Size to use Performance-Based Program

One entity's population of components should be large enough to represent a sizeable sample of a vendor's overall population of manufactured devices. For this reason, the following assumptions are made:

B = 5%

z = 1.96 (This equates to a 95% confidence level)

π = 4%

Using the equation above, n=59.0.

Minimum Sample Size to evaluate Performance-Based Program

The number of components that should be included in a sample size for evaluation of the appropriate testing interval can be smaller because a lower confidence level is acceptable since the sample testing is repeated or updated annually. For this reason, the following assumptions are made:

B = 5%

z = 1.44 (85% confidence level)

π = 4%

Using the equation above, n=31.8.

Recommendation

Based on the above discussion, a sample size should be at least 30 to allow use of the equation mentioned. Using this and the results of the equation, the following numbers are recommended (and required within the standard):

Minimum Population Size to use Performance-Based Maintenance Program = 60

Minimum Sample Size to evaluate Performance-Based Program = 30.

Once the population segment is defined, then maintenance must begin within the intervals as outlined for the device described in the Tables 1-1 through 1-5. Time intervals can be lengthened provided the last year's worth of components tested (or the last 30 units maintained, whichever is more) had fewer than 4% Countable Events. It is notable that 4% is specifically chosen because an entity with a small population (30 units) would have to adjust its time intervals between maintenance if more than one Countable Event was found to have occurred during the last analysis period. A smaller percentage would require that entity to adjust the time interval between maintenance activities if even one unit is found out of tolerance or causes a Misoperation.

The minimum number of units that can be tested in any given year is 5% of the population. Note that this 5% threshold sets a practical limitation on total length of time between intervals at 20 years.

If at any time the number of Countable Events equals or exceeds 4% of the last year's tested components (or the last 30 units maintained, whichever is more), then the time period between manual maintenance activities must be decreased. There is a time limit on reaching the decreased time at which the Countable Events is less than 4%; this must be attained within three years.

Performance-Based Program Evaluation Example

The 4% performance target was derived as a protection system performance target and was selected based on the drafting team's experience and studies performed by several utilities. This is not derived from the performance of discrete devices. Microprocessor relays and electromechanical relays have different performance levels. It is not appropriate to compare these performance levels to each other. The performance of the segment should be compared to the 4% performance criteria.

In consideration of the use of Performance Based Maintenance (PBM), the user should consider the effects of extended testing intervals and the established 4% failure rate. In the table shown below, the segment is 1000 units. As the testing interval (in years) increases, the number of units tested each year decreases. The number of countable events allowed is 4% of the tested units. Countable events are the failure of a Component requiring repair or replacement, any corrective actions performed during the maintenance test on the units within the testing segment (units per year), or any misoperation attributable to hardware failure or calibration failure found within the entire segment (1000 units) during the testing year.

Example: 1000 units in the segment with a testing interval of 8 years: The number of units tested each year will be 125 units. The total allowable countable events equals: 125 X .04 = 5. This number includes failure of a Component requiring repair or replacement, corrective issues found during testing, and the total number of misoperations (attributable to hardware or calibration failure within the testing year) associated with the entire segment of 1000 units.

Example: 1000 units in the segment with a testing interval of 16 years: The number of units tested each year will be 63 units. The total allowable countable events equals: 63 X .04 = 2.5.

As shown in the above examples, doubling the testing interval reduces the number of allowable events by half.

Total number of units in the segment	1000
Failure rate	4.00%

Testing Intervals (Years)	Units Per Year	Acceptable Number of Countable Events per year	Yearly Failure Rate Based on 1000 Units in Segment
1	1000.00	40.00	4.00%
2	500.00	20.00	2.00%
4	250.00	10.00	1.00%
6	166.67	6.67	0.67%
8	125.00	5.00	0.50%
10	100.00	4.00	0.40%
12	83.33	3.33	0.33%
14	71.43	2.86	0.29%
16	62.50	2.50	0.25%
18	55.56	2.22	0.22%
20	50.00	2.00	0.20%

Using the prior year's data, determine the maximum allowable maintenance interval for each Segment such that the Segment experiences Countable Events on no more than 4% of the Components within the Segment, for the greater of either the last 30 Components maintained or all Components maintained in the previous year.

Segment – Components of a consistent design standard, or a particular model or type from a single manufacturer that typically share other common elements. Consistent performance is expected across the entire population of a Segment. A Segment must contain at least sixty (60) individual Components.

Countable Event – A failure of a Component requiring repair or replacement, any condition discovered during the maintenance activities in Tables 1-1 through 1-5, Table 3,~~ and~~ Table 4-1 through Table 4-2, and Table5, which requires corrective action or a Protection System Misoperation attributed to hardware failure or calibration failure. Misoperations due to product design errors, software errors, relay settings different from specified settings, Protection System Component,~~ or~~ Automatic Reclosing or Sudden Pressure Relaying configuration or application errors are not included in Countable Events.

9.2 Frequently Asked Questions:

I'm a small entity and cannot aggregate a population of Protection System components to establish a segment required for a Performance-Based Protection System Maintenance Program. How can I utilize that opportunity?

Multiple asset owning entities may aggregate their individually owned populations of individual Protection System components to create a segment that crosses ownership boundaries. All entities participating in a joint program should have a single documented joint management process, with consistent Protection System Maintenance Programs (practices, maintenance intervals and criteria), for which the multiple owners are individually responsible with respect to the requirements of the Standard. The requirements established for Performance-Based Maintenance must be met for the overall aggregated program on an ongoing basis.

The aggregated population should reflect all factors that affect consistent performance across the population, including any relevant environmental factors such as geography, power-plant vs. substation, and weather conditions.

Can an owner go straight to a Performance-Based Maintenance program schedule, if they have previously gathered records?

Yes. An owner can go to a Performance-Based Maintenance program immediately. The owner will need to comply with the requirements of a Performance-Based Maintenance program as listed in the Standard. Gaps in the data collected will not be allowed; therefore, if an owner finds that a gap exists such that they cannot prove that they have collected the data as required for a Performance-Based Maintenance program then they will need to wait until they can prove compliance.

When establishing a Performance-Based Maintenance program, can I use test data from the device manufacturer, or industry survey results, as results to help establish a basis for my Performance-Based intervals?

No, you must use actual in-service test data for the components in the segment.

What types of Misoperations or events are not considered Countable Events in the Performance-Based Protection System Maintenance (PBM) Program?

Countable Events are intended to address conditions that are attributed to hardware failure or calibration failure; that is, conditions that reflect deteriorating performance of the component. These conditions include any condition where the device previously worked properly, then, due to changes within the device, malfunctioned or degraded to the point that re-calibration (to within the entity's tolerance) was required.

For this purpose of tracking hardware issues, human errors resulting in Protection System Misoperations during system installation or maintenance activities are not considered Countable Events. Examples of excluded human errors include relay setting errors, design errors, wiring errors, inadvertent tripping of devices during testing or installation, and misapplication of Protection System components. Examples of misapplication of Protection System components include wrong CT or PT tap position, protective relay function misapplication, and components not specified correctly for their installation. Obviously, if one is setting up relevant data about hardware failures then human failures should be eliminated from the hardware performance analysis.

One example of human-error is not pertinent data might be in the area of testing "86" lock-out relays (LOR). "Entity A" has two types of LOR's type "X" and type "Y"; they want to move into a performance based maintenance interval. They have 1000 of each type, so the population variables are met. During electrical trip testing of all of their various schemes over the initial six-year interval they find zero type "X" failures, but human error led to tripping a BES Element 100 times; they find 100 type "Y" failures and had an additional 100 human-error caused tripping incidents. In this example the human-error caused Misoperations should not be used to judge the performance of either type of LOR. Analysis of the data might lead "Entity A" to change time intervals. Type "X" LOR can be placed into extended time interval testing because of its low failure

rate (zero failures) while Type "Y" would have to be tested more often than every 6 calendar years (100 failures divided by 1000 units exceeds the 4% tolerance level).

Certain types of Protection System component errors that cause Misoperations are not considered Countable Events. Examples of excluded component errors include device malfunctions that are correctable by firmware upgrades and design errors that do not impact protection function.

What are some examples of methods of correcting segment perfomance for Performance-Based Maintenance?

There are a number of methods that may be useful for correcting segment performance for mal-performing segments in a Performance-Based Maintenance system. Some examples are listed below.

- The maximum allowable interval, as established by the Performance-Based Maintenance system, can be decreased. This may, however, be slow to correct the performance of the segment.
- Identifiable sub-groups of components within the established segment, which have been identified to be the mal-performing portion of the segment, can be broken out as an independent segment for target action. Each resulting segment must satisfy the minimum population requirements for a Performance-Based Maintenance program in order to remain within the program.
- Targeted corrective actions can be taken to correct frequently occurring problems. An example would be replacement of capacitors within electromechanical distance relays if bad capacitors were determined to be the cause of the mal-performance.
- components within the mal-performing segment can be replaced with other components (electromechanical distance relays with microprocessor relays, for example) to remove the mal-performing segment.

If I find (and correct) a Unresolved Maintenance Issue as a result of a Misoperation investigation (Re: PRC-004), how does this affect my Performance-Based Maintenance program?

If you perform maintenance on a Protection System component for any reason (including as part of a PRC-004 required Misoperation investigation/corrective action), the actions performed can count as a maintenance activity provided the activities in the relevant Tables have been done, and, if you desire, "reset the clock" on everything you've done. In a Performance-Based Maintenance program, you also need to record the Unresolved Maintenance Issue as a Countable Event within the relevant component group segment and use it in the analysis to determine your correct Performance-Based Maintenance interval for that component group. Note that "resetting the clock" should not be construed as interfering with an entity's routine testing schedule because the "clock-reset" would actually make for a decreased time interval by the time the next routine test schedule comes around.

For example a relay scheme, consisting of four relays, is tested on 1-1-11 and the PSMP has a time interval of 3 calendar years with an allowable extension of 1 calendar year. The relay would be due again for routine testing before the end of the year 2015. This mythical relay scheme has a Misoperation on 6-1-12 that points to one of the four relays as bad. Investigation proves a bad relay and a new one is tested and installed in place of the original. This replacement relay actually could be retested before the end of the year 2016 (clock-reset) and not be out of compliance. This requires tracking maintenance by individual relays and is allowed. However, many companies schedule maintenance in other ways like by substation or by circuit breaker or by relay scheme. By these methods of tracking maintenance that "replaced relay" will be retested before the end of the year 2015. This is also acceptable. In no case was a particular relay tested beyond the PSMP of four years max, nor was the 6 year max of the Standard exceeded. The entity can reset the clock if they desire or the entity can continue with original schedules and, in effect, test even more frequently.

Why are batteries excluded from PBM? What about exclusion of batteries from condition based maintenance?

Batteries are the only element of a Protection System that is a perishable item with a shelf life. As a perishable item batteries require not only a constant float charge to maintain their freshness (charge), but periodic inspection to determine if there are problems associated with their aging process and testing to see if they are maintaining a charge or can still deliver their rated output as required.

Besides being perishable, a second unique feature of a battery that is unlike any other Protection System element is that a battery uses chemicals, metal alloys, plastics, welds, and bonds that must interact with each other to produce the constant dc source required for Protection Systems, undisturbed by ac system Disturbances.

No type of battery manufactured today for Protection System application is free from problems that can only be detected over time by inspection and test. These problems can arise from variances in the manufacturing process, chemicals and alloys used in the construction of the individual cells, quality of welds and bonds to connect the components, the plastics used to make batteries and the cell forming process for the individual battery cells.

Other problems that require periodic inspection and testing can result from transportation from the factory to the job site, length of time before a charge is put on the battery, the method of installation, the voltage level and duration of equalize charges, the float voltage level used, and the environment that the battery is installed in.

All of the above mentioned factors and several more not discussed here are beyond the control of the Functional Entities that want to use a Performance-Based Protection System Maintenance (PBM) program. These inherent variances in the aging process of a battery cell make establishment of a designated segment based on manufacturer and type of battery impossible.

The whole point of PBM is that if all variables are isolated then common aging and performance criteria would be the same. However, there are too many variables in the electrochemical process to completely isolate all of the performance-changing criteria.

Similarly, Functional Entities that want to establish a condition-based maintenance program using the highest levels of monitoring, resulting in the least amount of hands-on maintenance activity, cannot completely eliminate some periodic maintenance of the battery used in a station dc supply. Inspection of the battery is required on a Maximum Maintenance Interval listed in the tables due to the aging processes of station batteries. However, higher degrees of monitoring of a battery can eliminate the requirement for some periodic testing and some inspections (see Table 1-4).

Please provide an example of the calculations involved in extending maintenance time intervals using PBM.

Entity has 1000 GE-HEA lock-out relays; this is greater than the minimum sample requirement of 60. They start out testing all of the relays within the prescribed Table requirements (6 year max) by testing the relays every 5 years. The entity's plan is to test 200 units per year; this is greater than the minimum sample size requirement of 30. For the sake of example only the following will show 6 failures per year, reality may well have different numbers of failures every year. PBM requires annual assessment of failures found per units tested. After the first year of tests the entity finds 6 failures in the 200 units tested. 6/200= 3% failure rate. This entity is now allowed to extend the maintenance interval if they choose. The entity chooses to extend the maintenance interval of this population segment out to 10 years. This represents a rate of 100 units tested per year; entity selects 100 units to be tested in the following year. After that year of testing these 100 units the entity again finds 6 failed units. 6/100= 6% failures. This entity has now exceeded the acceptable failure rate for these devices and must accelerate testing of all of the units at a higher rate such that the failure rate is found to be less than 4% per year; the entity has three years to get this failure rate down to 4% or less (per year). In response to the 6% failure rate, the entity decreases the testing interval to 8 years. This means that they will now test 125 units per year (1000/8). The entity has just two years left to get the test rate corrected.

After a year, they again find six failures out of the 125 units tested. 6/125= 5% failures. In response to the 5% failure rate, the entity decreases the testing interval to seven years. This means that they will now test 143 units per year (1000/7). The entity has just one year left to get the test rate corrected. After a year, they again find six failures out of the 143 units tested. 6/143= 4.2% failures.

(Note that the entity has tried five years and they were under the 4% limit and they tried seven years and they were over the 4% limit. They must be back at 4% failures or less in the next year so they might simply elect to go back to five years.)

Instead, in response to the 5% failure rate, the entity decreases the testing interval to six years. This means that they will now test 167 units per year (1000/6). After a year, they again find six failures out of the 167 units tested. 6/167= 3.6% failures. Entity found that they could maintain the failure rate at no more than 4% failures by maintaining the testing interval at six years or less. Entity chose six-year interval and effectively extended their TBM (five years) program by 20%.

A note of practicality is that an entity will probably be in better shape to lengthen the intervals between tests if the failure rate is less than 2%. But the requirements allow for annual adjustments, if the entity desires. As a matter of maintenance management, an ever-changing test rate (units tested/year) may be un-workable.

Note that the "5% of components" requirement effectively sets a practical limit of 20 year maximum PBM interval. Also of note is the "3 years" requirement; an entity might arbitrarily extend time intervals from six years to 20 years. In the event that an entity finds a failure rate greater than 4%, then the test rate must be accelerated such that within three years the failure rate must be brought back down to 4% or less.

Here is a table that demonstrates the values discussed:

Year #	Total Population (P)	Test Interval (I)	Units to be Tested (U= P/I)	# of Failures Found (F)	Failure Rate (=F/U)	Decision to Change Interval Yes or No	Interval Chosen
1	1000	5 yrs	200	6	3%	Yes	10 yrs
2	1000	10 yrs	100	6	6%	Yes	8 yrs
3	1000	8 yrs	125	6	5%	Yes	7 yrs
4	1000	7 yrs	143	6	4.2%	Yes	6 yrs
5	1000	6 yrs	167	6	3.6%	No	6 yrs

Please provide an example of the calculations involved in extending maintenance time intervals using PBM for control circuitry.

Note that the following example captures "Control Circuitry" as all of the trip paths associated with a particular trip coil of a circuit breaker. An entity is not restricted to this method of counting control circuits. Perhaps another method an entity would prefer would be to simply track every individual (parallel) trip path. Or perhaps another method would be to track all of the trip outputs from a specific (set) of relays protecting a specific element. Under the included definition of "component":

The designation of what constitutes a control circuit component is very dependent upon how an entity performs and tracks the testing of the control circuitry. Some entities test their control circuits on a breaker basis whereas others test their circuitry on a local zone of protection basis. Thus, entities are allowed the latitude to designate their own definitions of control circuit components. Another example of where the entity has some discretion on determining what constitutes a single component is the voltage and current sensing devices, where the entity may choose either to designate a full three-phase set of such devices or a single device as a single component.

And in Attachment A (PBM) the definition of Segment:

Segment –*Components of a consistent design standard, or a particular model or type from a single manufacturer that typically share other common elements. Consistent performance is expected across the entire population of a segment. A segment must contain at least sixty (60) individual components.*

Example:

Entity has 1,000 circuit breakers, all of which have two trip coils, for a total of 2,000 trip coils; if all circuitry was designed and built with a consistent (internal entity) standard, then this is greater than the minimum sample requirement of 60.

For the sake of further example, the following facts are given:

Half of all relay panels (500) were built 40 years ago by an outside contractor, consisted of asbestos wrapped 600V-insulation panel wiring, and the cables exiting the control house are THHN pulled in conduit direct to exactly half of all of the various circuit breakers. All of the relay panels and cable pulls were built with consistent standards and consistent performance standard expectations within the segment (which is greater than 60). Each relay panel has redundant microprocessor (MPC) relays (retrofitted); each MPC relay supplies an individual trip output to each of the two trip coils of the assigned circuit breaker.

Approximately 35 years ago, the entity developed their own internal construction crew and now builds all of their own relay panels from parts supplied from vendors that meet the entity's specifications, including SIS 600V insulation wiring and copper-sheathed cabling within the direct conduits to circuit breakers. The construction crew uses consistent standards in the construction. This newer segment of their control circuitry population is different than the original segment, consistent (standards, construction and performance expectations) within the new segment and constitutes the remainder of the entity's population (another 500 panels and the cabling to the remaining 500 circuit breakers). Each relay panel has redundant microprocessor (MPC) relays; each MPC relay supplies an individual trip output to each of the two trip coils of the assigned circuit breaker. Every trip path in this newer segment has a device that monitors the voltage

directly across the trip contacts of the MPC relays and alarms via RTU and SCADA to the operations control room. This monitoring device, when not in alarm, demonstrates continuity all the way through the trip coil, cabling and wiring back to the trip contacts of the MPC relay.

The entity is tracking 2,000 trip coils (each consisting of multiple trip paths) in each of these two segments. But half of all of the trip paths are monitored; therefore, the trip paths are continuously tested and the circuit will alarm when there is a failure. These alarms have to be verified every 12 years for correct operation.

The entity now has 1,000 trip coils (and associated trip paths) remaining that they have elected to count as control circuits. The entity has instituted a process that requires the verification of every trip path to each trip coil (one unit), including the electrical activation of the trip coil. (The entity notes that the trip coils will have to be tripped electrically more often than the trip path verification, and is taking care of this activity through other documentation of Real-time Fault operations.)

They start out testing all of the trip coil circuits within the prescribed Table requirements (12-year max) by testing the trip circuits every 10 years. The entity's plan is to test 100 units per year; this is greater than the minimum sample size requirement of 30. For the sake of example only, the following will show three failures per year; reality may well have different numbers of failures every year. PBM requires annual assessment of failures found per units tested. After the first year of tests, the entity finds three failures in the 100 units tested. 3/100= 3% failure rate.

This entity is now allowed to extend the maintenance interval, if they choose. The entity chooses to extend the maintenance interval of this population segment out to 20 years. This represents a rate of 50 units tested per year; entity selects 50 units to be tested in the following year. After that year of testing these 50 units, the entity again finds three failed units. 3/50= 6% failures.

This entity has now exceeded the acceptable failure rate for these devices and must accelerate testing of all of the units at a higher rate, such that the failure rate is found to be less than 4% per year; the entity has three years to get this failure rate down to 4% or less (per year).

In response to the 6% failure rate, the entity decreases the testing interval to 16 years. This means that they will now test 63 units per year (1000/16). The entity has just two years left to get the test rate corrected. After a year, they again find three failures out of the 63 units tested. 3/63= 4.76% failures.

In response to the >4% failure rate, the entity decreases the testing interval to 14 years. This means that they will now test 72 units per year (1000/14). The entity has just one year left to get the test rate corrected. After a year, they again find three failures out of the 72 units tested. 3/72= 4.2% failures.

(Note that the entity has tried 10 years, and they were under the 4% limit; and they tried 14 years, and they were over the 4% limit. They must be back at 4% failures or less in the next year, so they might simply elect to go back to 10 years.)

Instead, in response to the 4.2% failure rate, the entity decreases the testing interval to 12 years. This means that they will now test 84 units per year (1000/12). After a year, they again find three failures out of the 84 units tested. 3/84= 3.6% failures.

Entity found that they could maintain the failure rate at no more than 4% failures by maintaining the testing interval at 12 years or less. Entity chose 12-year interval, and effectively extended their TBM (10 years) program by 20%.

A note of practicality is that an entity will probably be in better shape to lengthen the intervals between tests if the failure rate is less than 2%. But the requirements allow for annual adjustments if the entity desires. As a matter of maintenance management, an ever-changing test rate (units tested / year) may be un-workable.

Note that the "5% of components" requirement effectively sets a practical limit of 20-year maximum PBM interval. Also of note is the "3 years" requirement; an entity might arbitrarily extend time intervals from six years to 20 years. In the event that an entity finds a failure rate greater than 4%, then the test rate must be accelerated such that within three years the failure rate must be brought back down to 4% or less.

Here is a table that demonstrates the values discussed:

Year #	Total Population (P)	Test Interval (I)	Units to be Tested (U= P/I)	# of Failures Found (F)	Failure Rate (=F/U)	Decision to Change Interval Yes or No	Interval Chosen
1	1000	10 yrs	100	3	3%	Yes	20 yrs
2	1000	20 yrs	50	3	6%	Yes	16yrs
3	1000	16 yrs	63	3	4.8%	Yes	14 yrs
4	1000	14 yrs	72	3	4.2%	Yes	12 yrs
5	1000	12 yrs	84	3	3.6%	No	12 yrs

Please provide an example of the calculations involved in extending maintenance time intervals using PBM for voltage and current sensing devices.

Note that the following example captures "voltage and current inputs to the protective relays" as all of the various current transformer and potential transformer signals associated with a particular set of relays used for protection of a specific Element. This entity calls this set of protective relays a "Relay Scheme." Thus, this entity chooses to count PT and CT signals as a group instead of individually tracking maintenance activities to specific bushing CT's or specific PT's. An entity is not restricted to this method of counting voltage and current devices, signals and paths. Perhaps another method an entity would prefer would be to simply track every individual PT and CT. Note that a generation maintenance group may well select the latter because they may elect to perform routine off-line tests during generator outages, whereas a transmission maintenance group might create a process that utilizes Real-time system values measured at the relays. Under the included definition of "component":

The designation of what constitutes a control circuit component is very dependent upon how an entity performs and tracks the testing of the control circuitry. Some entities test their control circuits on a breaker basis whereas others test their circuitry on a local zone of protection basis. Thus, entities are allowed the latitude to designate their own definitions of control circuit components. Another example of where the entity has some discretion on determining what constitutes a single component is the voltage and current sensing devices, where the entity may choose either to designate a full three-phase set of such devices or a single device as a single component.

And in Attachment A (PBM) the definition of Segment:

Segment –*Components of a consistent design standard, or a particular model or type from a single manufacturer that typically share other common elements. Consistent performance is expected across the entire population of a segment. A segment must contain at least sixty (60) individual components.*

Example:

Entity has 2000 "Relay Schemes," all of which have three current signals supplied from bushing CTs, and three voltage signals supplied from substation bus PT's. All cabling and circuitry was designed and built with a consistent (internal entity) standard, and this population is greater than the minimum sample requirement of 60.

For the sake of further example the following facts are given:

Half of all relay schemes (1,000) are supplied with current signals from ANSI STD C800 bushing CTs and voltage signals from PTs built by ACME Electric MFR CO. All of the relay panels and cable pulls were built with consistent standards, and consistent performance standard expectations exist for the consistent wiring, cabling and instrument transformers within the segment (which is greater than 60).

The other half of the entity's relay schemes have MPC relays with additional monitoring built-in that compare DNP values of voltages and currents (or Watts and VARs), as interpreted by the MPC relays and alarm for an entity-accepted tolerance level of accuracy. This newer segment of their "Voltage and Current Sensing" population is different than the original segment, consistent (standards, construction and performance expectations) within the new segment and constitutes the remainder of the entity's population.

The entity is tracking many thousands of voltage and current signals within 2,000 relay schemes (each consisting of multiple voltage and current signals) in each of these two segments. But half of all of the relay schemes voltage and current signals are monitored; therefore, the voltage and current signals are continuously tested and the circuit will alarm when there is a failure; these alarms have to be verified every 12 years for correct operation.

The entity now has 1,000 relay schemes worth of voltage and current signals remaining that they have elected to count within their relay schemes designation. The entity has instituted a process that requires the verification of these voltage and current signals within each relay scheme (one unit).

(Please note - a problem discovered with a current or voltage signal found at the relay could be caused by anything from the relay, all the way to the signal source itself. Having many sources of problems can easily increase failure rates beyond the rate of failures of just one item (for example just PTs). It is the intent of the SDT to minimize failure rates of all of the equipment to an acceptable level; thus, any failure of any item that gets the signal from source to relay is counted. It is for this reason that the SDT chose to set the boundary at the ability of the signal to be delivered all the way to the relay.

The entity will start out measuring all of the relay scheme voltage and currents at the individual relays within the prescribed Table requirements (12 year max) by measuring the voltage and current values every 10 years. The entity's plan is to test 100 units per year; this is greater than the minimum sample size requirement of 30. For the sake of example only, the following will show three failures per year; reality may well have different numbers of failures every year. PBM requires annual assessment of failures found per units tested. After the first year of tests, the entity finds three failures in the 100 units tested. 3/100= 3% failure rate.

This entity is now allowed to extend the maintenance interval, if they choose. The entity chooses to extend the maintenance interval of this population segment out to 20 years. This represents a rate of 50 units tested per year; entity selects 50 units to be tested in the following year. After that year of testing these 50 units, the entity again finds three failed units. 3/50= 6% failures.

This entity has now exceeded the acceptable failure rate for these devices and must accelerate testing of all of the units at a higher rate, such that the failure rate is found to be less than 4% per year; the entity has three years to get this failure rate down to 4% or less (per year).

In response to the 6% failure rate, the entity decreases the testing interval to 16 years. This means that they will now test 63 units per year (1000/16). The entity has just two years left to get the test rate corrected. After a year, they again find three failures out of the 63 units tested. 3/63= 4.76% failures.

In response to the >4%failure rate, the entity decreases the testing interval to 14 years. This means that they will now test 72 units per year (1000/14). The entity has just one year left to get the test rate corrected. After a year, they again find three failures out of the 72 units tested. 3/72= 4.2% failures.

(Note that the entity has tried 10 years, and they were under the 4% limit; and they tried 14 years, and they were over the 4% limit. They must be back at 4% failures or less in the next year, so they might simply elect to go back to 10 years.)

Instead, in response to the 4.2% failure rate, the entity decreases the testing interval to 12 years. This means that they will now test 84 units per year (1,000/12). After a year, they again find three failures out of the 84 units tested. 3/84= 3.6% failures.

Entity found that they could maintain the failure rate at no more than 4% failures by maintaining the testing interval at 12 years or less. Entity chose 12-year interval and effectively extended their TBM (10 years) program by 20%.

A note of practicality is that an entity will probably be in better shape to lengthen the intervals between tests if the failure rate is less than 2%. But the requirements allow for annual adjustments, if the entity desires. As a matter of maintenance management, an ever-changing test rate (units tested/year) may be un-workable.

Note that the "5% of components" requirement effectively sets a practical limit of 20-year maximum PBM interval. Also of note is the "3 years" requirement; an entity might arbitrarily extend time intervals from six years to 20 years. In the event that an entity finds a failure rate greater than 4%, then the test rate must be accelerated such that within three years the failure rate must be brought back down to 4% or less.

Here is a table that demonstrates the values discussed:

Year #	Total Population (P)	Test Interval (I)	Units to be Tested (U= P/I)	# of Failures Found (F)	Failure Rate (=F/U)	Decision to Change Interval Yes or No	Interval Chose
1	1000	10 yrs	100	3	3%	Yes	20 yrs
2	1000	20 yrs	50	3	6%	Yes	16yrs
3	1000	16 yrs	63	3	4.8%	Yes	14 yrs
4	1000	14 yrs	72	3	4.2%	Yes	12 yrs
5	1000	12 yrs	84	3	3.6%	No	12 yrs

10. Overlapping the Verification of Sections of the Protection System

Tables 1-1 through 1-5 require that every Protection System component be periodically verified. One approach, but not the only method, is to test the entire protection scheme as a unit, from the secondary windings of voltage and current sources to breaker tripping. For practical ongoing verification, sections of the Protection System may be tested or monitored individually. The boundaries of the verified sections must overlap to ensure that there are no gaps in the verification. See Appendix A of this Supplementary Reference for additional discussion on this topic.

All of the methodologies expressed within this report may be combined by an entity, as appropriate, to establish and operate a maintenance program. For example, a Protection System may be divided into multiple overlapping sections with a different maintenance methodology for each section:

- Time-based maintenance with appropriate maximum verification intervals for categories of equipment, as given in the Tables 1-1 through 1-5;
- Monitoring as described in Tables 1-1 through 1-5;
- A Performance-Based Maintenance program as described in Section 9 above, or Attachment A of the standard;
- Opportunistic verification using analysis of Fault records, as described in Section 11

10.1 Frequently Asked Questions:

My system has alarms that are gathered once daily through an auto-polling system; this is not really a conventional SCADA system but does it meet the Table 1 requirements for inclusion as a monitored system?

Yes, provided the auto-polling that gathers the alarms reports those alarms to a location where the action can be initiated to correct the Unresolved Maintenance Issue. This location does not have to be the location of the engineer or the technician that will eventually repair the problem, but rather a location where the action can be initiated.

11. Monitoring by Analysis of Fault Records

Many users of microprocessor relays retrieve Fault event records and oscillographic records by data communications after a Fault. They analyze the data closely if there has been an apparent Misoperation, as NERC standards require. Some advanced users have commissioned automatic Fault record processing systems that gather and archive the data. They search for evidence of component failures or setting problems hidden behind an operation whose overall outcome seems to be correct. The relay data may be augmented with independently captured Digital Fault Recorder (DFR) data retrieved for the same event.

Fault data analysis comprises a legitimate CBM program that is capable of reducing the need for a manual time-interval based check on Protection Systems whose operations are analyzed. Even electromechanical Protection Systems instrumented with DFR channels may achieve some CBM benefit. The completeness of the verification then depends on the number and variety of Faults in the vicinity of the relay that produce relay response records and the specific data captured.

A typical Fault record will verify particular parts of certain Protection Systems in the vicinity of the Fault. For a given Protection System installation, it may or may not be possible to gather within a reasonable amount of time an ensemble of internal and external Fault records that completely verify the Protection System.

For example, Fault records may verify that the particular relays that tripped are able to trip via the control circuit path that was specifically used to clear that Fault. A relay or DFR record may indicate correct operation of the protection communications channel. Furthermore, other nearby Protection Systems may verify that they restrain from tripping for a Fault just outside their respective zones of protection. The ensemble of internal Fault and nearby external Fault event data can verify major portions of the Protection System, and reset the time clock for the Table 1 testing intervals for the verified components only.

What can be shown from the records of one operation is very specific and limited. In a panel with multiple relays, only the specific relay(s) whose operation can be observed without ambiguity should be used. Be careful about using Fault response data to verify that settings or calibration are correct. Unless records have been captured for multiple Faults close to either side of a setting boundary, setting or calibration could still be incorrect.

PMU data, much like DME data, can be utilized to prove various components of the Protection System. Obviously, care must be taken to attribute proof only to the parts of a Protection System that can actually be proven using the PMU or DME data.

If Fault record data is used to show that portions or all of a Protection System have been verified to meet Table 1 requirements, the owner must retain the Fault records used, and the maintenance-related conclusions drawn from this data and used to defer Table 1 tests, for at least the retention time interval given in Section 8.2.

11.1 Frequently Asked Questions:

I use my protective relays for Fault and Disturbance recording, collecting oscillographic records and event records via communications for Fault analysis to meet NERC and DME requirements. What are the maintenance requirements for the relays?

For relays used only as Disturbance Monitoring Equipment, NERC Standard PRC-018-1 R3 & R6 states the maintenance requirements and is being addressed by a standards activity that is revising PRC-002-1 and PRC-018-1. For protective relays "that are designed to provide protection for the BES," this standard applies, even if they also perform DME functions.

12. Importance of Relay Settings in Maintenance Programs

In manual testing programs, many utilities depend on pickup value or zone boundary tests to show that the relays have correct settings and calibration. Microprocessor relays, by contrast, provide the means for continuously monitoring measurement accuracy. Furthermore, the relay digitizes inputs from one set of signals to perform all measurement functions in a single self-monitoring microprocessor system. These relays do not require testing or calibration of each setting.

However, incorrect settings may be a bigger risk with microprocessor relays than with older relays. Some microprocessor relays have hundreds or thousands of settings, many of which are critical to Protection System performance.

Monitoring does not check measuring element settings. Analysis of Fault records may or may not reveal setting problems. To minimize risk of setting errors after commissioning, the user should enforce strict settings data base management, with reconfirmation (manual or automatic) that the installed settings are correct whenever maintenance activity might have changed them; for background and guidance, see [5] in References.

Table 1 requires that settings must be verified to be as specified. The reason for this requirement is simple: With legacy relays (non-microprocessor protective relays), it is necessary to know the value of the intended setting in order to test, adjust and calibrate the relay. Proving that the relay works per specified setting was the de facto procedure. However, with the advanced microprocessor relays, it is possible to change relay settings for the purpose of verifying specific functions and then neglect to return the settings to the specified values. While there is no specific requirement to maintain a settings management process, there remains a need to verify that the settings left in the relay are the intended, specified settings. This need may manifest itself after any of the following:

- One or more settings are changed for any reason.
- A relay fails and is repaired or replaced with another unit.
- A relay is upgraded with a new firmware version.

12.1 Frequently Asked Questions:

How do I approach testing when I have to upgrade firmware of a microprocessor relay?

The entity should ensure that the relay continues to function properly after implementation of firmware changes. Some entities may have a R&D department that might routinely run acceptance tests on devices with firmware upgrades before allowing the upgrade to be installed. Other entities may rely upon the vigorous testing of the firmware OEM. An entity has the latitude to install devices and/or programming that they believe will perform to their satisfaction. If an entity should choose to perform the maintenance activities specified in the Tables following a firmware upgrade, then they may, if they choose, reset the time clock on that set of maintenance activities so that they would not have to repeat the maintenance on its regularly scheduled cycle.

(However, for simplicity in maintenance schedules, some entities may choose to not reset this time clock; it is merely a suggested option.)

If I upgrade my old relays, then do I have to maintain my previous equipment maintenance documentation?

If an equipment item is repaired or replaced, then the entity can restart the maintenance-activity-time-interval-clock, if desired; however, the replacement of equipment does not remove any documentation requirements. The requirements in the standard are intended to ensure that an entity has a maintenance plan, and that the entity adheres to minimum activities and maximum time intervals. The documentation requirements are intended to help an entity demonstrate compliance. For example, saving the dates and records of the last two maintenance activities is intended to demonstrate compliance with the interval. Therefore, if you upgrade or replace equipment, then you still must maintain the documentation for the previous equipment, thus demonstrating compliance with the time interval requirement prior to the replacement action.

We have a number of installations where we have changed our Protection System components. Some of the changes were upgrades, but others were simply system rating changes that merely required taking relays "out-of-service". What are our responsibilities when it comes to "out-of-service" devices?

Assuming that your system up-rates, upgrades and overall changes meet any and all other requirements and standards, then the requirements of ~~PRC-005-3~~PRC-005-4 are simple – if the Protection System component performs a Protection System function, then it must be maintained. If the component no longer performs Protection System functions, then it does not require maintenance activities under the Tables of ~~PRC-005-3~~PRC-005-4. While many entities might physically remove a component that is no longer needed, there is no requirement in ~~PRC-005-3~~PRC-005-4 to remove such component(s). Obviously, prudence would dictate that an "out-of-service" device is truly made inactive. There are no record requirements listed in ~~PRC-005-3~~PRC-005-4 for Protection System components not used.

While performing relay testing of a protective device on our Bulk Electric System, it was discovered that the protective device being tested was either broken or out of calibration. Does this satisfy the relay testing requirement, even though the protective device tested bad, and may be unable to be placed back into service?

Yes, ~~PRC-005-3~~PRC-005-4 requires entities to perform relay testing on protective devices on a given maintenance cycle interval. By performing this testing, the entity has satisfied ~~PRC-005-3~~PRC-005-4 requirement, although the protective device may be unable to be returned to service under normal calibration adjustments. R5 states:

"R5. Each Transmission Owner, Generator Owner, and Distribution Provider shall demonstrate efforts to correct any identified Unresolved Maintenance Issues."

Also, when a failure occurs in a Protection System, power system security may be comprised, and notification of the failure must be conducted in accordance with relevant NERC standards.

If I show the protective device out of service while it is being repaired, then can I add it back as a new protective device when it returns? If not, my relay testing history would show that I was out of compliance for the last maintenance cycle.

The maintenance and testing requirements (R5) state "…shall demonstrate efforts to correct any identified Unresolved Maintenance Issues..." The type of corrective activity is not stated; however, it could include repairs or replacements.

Your documentation requirements will increase, of course, to demonstrate that your device tested bad and had corrective actions initiated. Your regional entity might ask about the status of your corrective actions.

13. Self-Monitoring Capabilities and Limitations

Microprocessor relay proponents have cited the self-monitoring capabilities of these products for nearly 20 years. Theoretically, any element that is monitored does not need a periodic manual test. A problem today is that the community of manufacturers and users has not created clear documentation of exactly what is and is not monitored. Some unmonitored but critical elements are buried in installed systems that are described as self-monitoring.

To utilize the extended time intervals allowed by monitoring, the user must document that the monitoring attributes of the device match the minimum requirements listed in the Table 1.

Until users are able to document how all parts of a system which are required for the protective functions are monitored or verified (with help from manufacturers), they must continue with the unmonitored intervals established in Table 1 and Table 3.

Going forward, manufacturers and users can develop mappings of the monitoring within relays, and monitoring coverage by the relay of user circuits connected to the relay terminals.

To enable the use of the most extensive monitoring (and never again have a hands-on maintenance requirement), the manufacturers of the microprocessor-based self-monitoring components in the Protection System should publish for the user a document or map that shows:

- How all internal elements of the product are monitored for any failure that could impact Protection System performance.
- Which connected circuits are monitored by checks implemented within the product; how to connect and set the product to assure monitoring of these connected circuits; and what circuits or potential problems are not monitored.

This manufacturer's information can be used by the registered entity to document compliance of the monitoring attributes requirements by:

- Presenting or referencing the product manufacturer's documents.
- Explaining in a system design document the mapping of how every component and circuit that is critical to protection is monitored by the microprocessor product(s) or by other design features.
- Extending the monitoring to include the alarm transmission Facilities through which failures are reported within a given time frame to allocate where action can be taken to initiate resolution of the alarm attributed to an Unresolved Maintenance Issue, so that failures of monitoring or alarming systems also lead to alarms and action.
- Documenting the plans for verification of any unmonitored components according to the requirements of Table 1 and Table 3.

13.1 Frequently Asked Questions:

I can't figure out how to demonstrate compliance with the requirements for the highest level of monitoring of Protection Systems. Why does this Maintenance Standard describe a maintenance program approach I cannot achieve?

Demonstrating compliance with the requirements for the highest level of monitoring any particular component of Protection Systems is likely to be very involved, and may include detailed manufacturer documentation of complete internal monitoring within a device, comprehensive design drawing reviews, and other detailed documentation. This standard does not presume to specify what documentation must be developed; only that it must be documented.

There may actually be some equipment available that is capable of meeting these highest levels of monitoring criteria, in which case it may be maintained according to the highest level of monitoring shown on the Tables. However, even if there is no equipment available today that can meet this level of monitoring, the standard establishes the necessary requirements for when such equipment becomes available.

By creating a roadmap for development, this provision makes the standard technology-neutral. The Standard Drafting Team wants to avoid the need to revise the standard in a few years to accommodate technology advances that may be coming to the industry.

14. Notification of Protection System or Automatic Reclosing Failures

When a failure occurs in a Protection System or Automatic Reclosing, power system security may be compromised, and notification of the failure must be conducted in accordance with relevant NERC standard(s). Knowledge of the failure may impact the system operator's decisions on acceptable Loading conditions.

This formal reporting of the failure and repair status to the system operator by the Protection System or Automatic Reclosing owner also encourages the system owner to execute repairs as rapidly as possible. In some cases, a microprocessor relay or carrier set can be replaced in hours; wiring termination failures may be repaired in a similar time frame. On the other hand, a component in an electromechanical or early-generation electronic relay may be difficult to find and may hold up repair for weeks. In some situations, the owner may have to resort to a temporary protection panel, or complete panel replacement.

15. Maintenance Activities

Some specific maintenance activities are a requirement to ensure reliability. An example would be that a BES entity could be prudent in its protective relay maintenance, but if its battery maintenance program is lacking, then reliability could still suffer. The NERC glossary outlines a Protection System as containing specific components. ~~PRC-005-3~~PRC-005-4 requires specific maintenance activities be accomplished within a specific time interval. As noted previously, higher technology equipment can contain integral monitoring capability that actually performs maintenance verification activities routinely and often; therefore, *manual intervention* to perform certain activities on these type components may not be needed.

15.1 Protective Relays (Table 1-1)

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 Element of the BES. Devices that sense thermal, vibration, seismic, ~~pressure,~~ gas, or any other non-electrical inputs are excluded.

Non-microprocessor based equipment is treated differently than microprocessor-based equipment in the following ways; the relays should meet the asset owners' tolerances:

- Non-microprocessor devices must be tested with voltage and/or current applied to the device.
- Microprocessor devices may be tested through the integral testing of the device.
    - There is no specific protective relay commissioning test or relay routine test mandated.
    - There is no specific documentation mandated.

15.1.1 Frequently Asked Questions:

What calibration tolerance should be applied on electromechanical relays?

Each entity establishes their own acceptable tolerances when applying protective relaying on their system. For some Protection System components, adjustment is required to bring measurement accuracy within the parameters established by the asset owner based on the specific application of the component. A calibration failure is the result if testing finds the specified parameters to be out of tolerance.

15.2 Voltage & Current Sensing Devices (Table 1-3)

These are the current and voltage sensing devices, usually known as instrument transformers. There is presently a technology available (fiber-optic Hall-effect) that does not utilize conventional transformer technology; these devices and other technologies that produce quantities that represent the primary values of voltage and current are considered to be a type of voltage and current sensing devices included in this standard.

The intent of the maintenance activity is to verify the input to the protective relay from the device that produces the current or voltage signal sample.

There is no specific test mandated for these components. The important thing about these signals is to know that the expected output from these components actually reaches the protective relay. Therefore, the proof of the proper operation of these components also demonstrates the integrity of the wiring (or other medium used to convey the signal) from the current and voltage sensing device, all the way to the protective relay. The following observations apply:

- There is no specific ratio test, routine test or commissioning test mandated.
- There is no specific documentation mandated.
- It is required that the signal be present at the relay.
- This expectation can be arrived at from any of a number of means; including, but not limited to, the following: By calculation, by comparison to other circuits, by commissioning tests, by thorough inspection, or by any means needed to verify the circuit meets the asset owner's Protection System maintenance program.
- An example of testing might be a saturation test of a CT with the test values applied at the relay panel; this, therefore, tests the CT, as well as the wiring from the relay all the back to the CT.
- Another possible test is to measure the signal from the voltage and/or current sensing devices, during Load conditions, at the input to the relay.
- Another example of testing the various voltage and/or current sensing devices is to query the microprocessor relay for the Real-time Loading; this can then be compared to other devices to verify the quantities applied to this relay. Since the input devices have supplied the proper values to the protective relay, then the verification activity has been satisfied. Thus, event reports (and oscillographs) can be used to verify that the voltage and current sensing devices are performing satisfactorily.
- Still another method is to measure total watts and vars around the entire bus; this should add up to zero watts and zero vars, thus proving the voltage and/or current sensing devices system throughout the bus.
- Another method for proving the voltage and/or current-sensing devices is to complete commissioning tests on all of the transformers, cabling, fuses and wiring.
- Any other method that verifies the input to the protective relay from the device that produces the current or voltage signal sample.

15.2.1 Frequently Asked Questions:

What is meant by "…verify the current and voltage circuit inputs from the voltage and current sensing devices to the protective relays …" Do we need to perform ratio, polarity and saturation tests every few years?

No. You must verify that the protective relay is receiving the expected values from the voltage and current-sensing devices (typically voltage and current transformers). This can be as difficult as is proposed by the question (with additional testing on the cabling and substation wiring to ensure that the values arrive at the relays); or simplicity can be achieved by other verification methods. While some examples follow, these are not intended to represent an all-inclusive list; technology advances and ingenuity should not be excluded from making comparisons and verifications:

- Compare the secondary values, at the relay, to a metering circuit, fed by different current transformers, monitoring the same line as the questioned relay circuit.
- Compare the individual phase secondary values at the relay panel (with additional testing on the panel wiring to ensure that the values arrive at those relays) with the other phases, and verify that residual currents are within expected bounds.
- Observe all three phase currents and the residual current at the relay panel with an oscilloscope, observing comparable magnitudes and proper phase relationship, with additional testing on the panel wiring to ensure that the values arrive at the relays.
- Compare the values, as determined by the questioned relay (such as, but not limited to, a query to the microprocessor relay) to another protective relay monitoring the same line, with currents supplied by different CTs.
- Compare the secondary values, at the relay with values measured by test instruments (such as, but not limited to multi-meters, voltmeter, clamp-on ammeters, etc.) and verified by calculations and known ratios to be the values expected. For example, a single PT on a 100KV bus will have a specific secondary value that, when multiplied by the PT ratio, arrives at the expected bus value of 100KV.
- Query SCADA for the power flows at the far end of the line protected by the questioned relay, compare those SCADA values to the values as determined by the questioned relay.
- Totalize the Watts and VARs on the bus and compare the totals to the values as seen by the questioned relay.

The point of the verification procedure is to ensure that all of the individual components are functioning properly; and that an ongoing proactive procedure is in place to re-check the various components of the protective relay measuring Systems.

Is wiring insulation or hi-pot testing required by this Maintenance Standard?

No, wiring insulation and equipment hi-pot testing are not specifically required by the Maintenance Standard. However, if the method of verifying CT and PT inputs to the relay involves some other method than actual observation of current and voltage transformer secondary inputs to the relay, it might be necessary to perform some sort of cable integrity test to verify that the instrument transformer secondary signals are actually making it to the relay and not being shunted off to ground. For instance, you could use CT excitation tests and PT turns ratio tests

and compare to baseline values to verify that the instrument transformer outputs are acceptable. However, to conclude that these acceptable transformer instrument output signals are actually making it to the relay inputs, it also would be necessary to verify the insulation of the wiring between the instrument transformer and the relay.

My plant generator and transformer relays are electromechanical and do not have metering functions, as do microprocessor- based relays. In order for me to compare the instrument transformer inputs to these relays to the secondary values of other metered instrument transformers monitoring the same primary voltage and current signals, it would be necessary to temporarily connect test equipment, like voltmeters and clamp on ammeters, to measure the input signals to the relays. This practice seems very risky, and a plant trip could result if the technician were to make an error while measuring these current and voltage signals. How can I avoid this risk? Also, what if no other instrument transformers are available which monitor the same primary voltage or current signal?

Comparing the input signals to the relays to the outputs of other independent instrument transformers monitoring the same primary current or voltage is just one method of verifying the instrument transformer inputs to the relays, but is not required by the standard. Plants can choose how to best manage their risk. If online testing is deemed too risky, offline tests, such as, but not limited to, CT excitation test and PT turns ratio tests can be compared to baseline data and be used in conjunction with CT and PT secondary wiring insulation verification tests to adequately "verify the current and voltage circuit inputs from the voltage and current sensing devices to the protective relays …" while eliminating the risk of tripping an in service generator or transformer. Similarly, this same offline test methodology can be used to verify the relay input voltage and current signals to relays when there are no other instrument transformers monitoring available for purposes of signal comparison.

15.3 Control circuitry associated with protective functions (Table 1-5)

This component of Protection Systems includes the trip coil(s) of the circuit breaker, circuit switcher or any other interrupting device. It includes the wiring from the batteries to the relays. It includes the wiring (or other signal conveyance) from every trip output to every trip coil. It includes any device needed for the correct processing of the needed trip signal to the trip coil of the interrupting device; this requirement is meant to capture inputs and outputs to and from a protective relay that are necessary for the correct operation of the protective functions. In short, every trip path must be verified; the method of verification is optional to the asset owner. An example of testing methods to accomplish this might be to verify, with a volt-meter, the existence of the proper voltage at the open contacts, the open circuited input circuit and at the trip coil(s). As every parallel trip path has similar failure modes, each trip path from relay to trip coil must be verified. Each trip coil must be tested to trip the circuit breaker (or other interrupting device) at least once. There is a requirement to operate the circuit breaker (or other interrupting device) at least once every six years as part of the complete functional test. If a suitable monitoring system is installed that verifies every parallel trip path, then the manual-intervention testing of those parallel trip paths can be eliminated; however, the actual operation of the circuit breaker must still occur at least once every six years. This six-year tripping requirement can be completed as easily as tracking the Real-time Fault-clearing operations on the circuit breaker, or tracking the trip coil(s) operation(s) during circuit breaker routine maintenance actions.

The circuit-interrupting device should not be confused with a motor-operated disconnect. The intent of this standard is to require maintenance intervals and activities on Protection Systems equipment, and not just all system isolating equipment.

It is necessary, however, to classify a device that actuates a high-speed auto-closing ground switch as an interrupting device, if this ground switch is utilized in a Protection System and forces a ground Fault to occur that then results in an expected Protection System operation to clear the forced ground Fault. The SDT believes that this is essentially a transferred-tripping device without the use of communications equipment. If this high-speed ground switch is "…designed to provide protection for the BES…" then this device needs to be treated as any other Protection System component. The control circuitry would have to be tested within 12 years, and any electromechanically operated device will have to be tested every six years. If the spring-operated ground switch can be disconnected from the solenoid triggering unit, then the solenoid triggering unit can easily be tested without the actual closing of the ground blade.

The dc control circuitry also includes each auxiliary tripping relay (94) and each lock-out relay (86) that may exist in any particular trip scheme. If the lock-out relays (86) are electromechanical type components, then they must be trip tested. The PSMT SDT considers these components to share some similarities in failure modes as electromechanical protective relays; as such, there is a six-year maximum interval between mandated maintenance tasks unless PBM is applied.

Contacts of the 86 and/or 94 that pass the trip current on to the circuit interrupting device trip coils will have to be checked as part of the 12 year requirement. Contacts of the 86 and/or 94 lock relay that operate non-BES interrupting devices are not required. Normally-open contacts that are not used to pass a trip signal and normally-closed contacts do not have to be verified. Verification of the tripping paths is the requirement.

~~While relays that do not respond to electrical quantities are presently excluded from this standard, their control circuits are included if the relay is installed to detect Faults on BES Elements. Thus, the control circuit of a BES transformer sudden pressure relay should be verified every 12 years, assuming its integrity is not monitored. While a sudden pressure relay control circuit is included within the scope of PRC-005-2, other alarming relay control circuits, (i.e., SF-6 low gas) are not included, even though they may trip the breaker being monitored.~~

New technology is also accommodated here; there are some tripping systems that have replaced the traditional hard-wired trip circuitry with other methods of trip-signal conveyance such as fiber-optics. It is the intent of the PSMT SDT to include this, and any other, technology that is used to convey a trip signal from a protective relay to a circuit breaker (or other interrupting device) within this category of equipment. The requirement for these systems is verification of the tripping path.

Monitoring of the control circuit integrity allows for no maintenance activity on the control circuit (excluding the requirement to operate trip coils and electromechanical lockout and/or tripping auxiliary relays). Monitoring of integrity means to monitor for continuity and/or presence of voltage on each trip path. For Ethernet or fiber-optic control systems, monitoring of integrity means to monitor communication ability between the relay and the circuit breaker.

~~The trip path from a sudden pressure device is a part of the Protection System control circuitry. The sensing element is omitted from PRC-005-3 testing requirements because the SDT is unaware of industry-recognized testing protocol for the sensing elements. The SDT believes that~~

~~Protection Systems that trip (or can trip) the BES should be included. This position is consistent with the currently-approved PRC-005-1b, consistent with the SAR for Project 2007-17, and understands this to be consistent with the position of FERC staff.~~

15.3.1 Frequently Asked Questions:

Is it permissible to verify circuit breaker tripping at a different time (and interval) than when we verify the protective relays and the instrument transformers?

Yes, provided the entire Protective System is tested within the individual component's maximum allowable testing intervals.

The Protection System Maintenance Standard describes requirements for verifying the tripping of circuit breakers. What is this telling me about maintenance of circuit breakers?

Requirements in ~~PRC-005-3~~PRC-005-4 are intended to verify the integrity of tripping circuits, including the breaker trip coil, as well as the presence of auxiliary supply (usually a battery) for energizing the trip coil if a protection function operates. Beyond this, ~~PRC-005-3~~PRC-005-4 sets no requirements for verifying circuit breaker performance, or for maintenance of the circuit breaker.

How do I test each dc Control Circuit trip path, as established in Table 1-5 "Protection System Control Circuitry (Trip coils and auxiliary relays)"?

Table 1-5 specifies that each breaker trip coil and lockout relays that carry trip current to a trip coil must be operated within the specified time period. The required operations may be via targeted maintenance activities, or by documented operation of these devices for other purposes such as Fault clearing.

Are high-speed ground switch trip coils included in the dc control circuitry?

Yes. ~~PRC-005-3~~PRC-005-4 includes high-speed grounding switch trip coils within the dc control circuitry to the degree that the initiating Protection Systems are characterized as "transmission Protection Systems."

Does the control circuitry and trip coil of a non-BES breaker, tripped via a BES protection component, have to be tested per Table 1.5? (Refer to Table 3 for examples 1 and 2) Example 1: A non-BES circuit breaker that is tripped via a Protection System to which ~~PRC-005-3~~PRC-005-4 applies might be (but is not limited to) a 12.5KV circuit breaker feeding (non-black-start) radial Loads but has a trip that originates from an under-frequency (81) relay.

- The relay must be verified.
- The voltage signal to the relay must be verified.
- All of the relevant dc supply tests still apply.
- The unmonitored trip circuit between the relay and any lock-out or auxiliary relay must be verified every 12 years.
- The unmonitored trip circuit between the lock-out (or auxiliary relay) and the non-BES breaker does not have to be proven with an electrical trip.
- In the case where there is no lock-out or auxiliary tripping relay used, the trip circuit to the non-BES breaker does not have to be proven with an electrical trip.

- The trip coil of the non-BES circuit breaker does not have to be individually proven with an electrical trip.

Example 2: A Transmission Owner may have a non-BES breaker that is tripped via a Protection System to which ~~PRC-005-3~~PRC-005-4 applies, which may be (but is not limited to) a 13.8 KV circuit breaker feeding (non-black-start) radial Loads but has a trip that originates from a BES 115KV line relay.

- The relay must be verified
- The voltage signal to the relay must be verified
- All of the relevant dc supply tests still apply
- The unmonitored trip circuit between the relay and any lock-out (86) or auxiliary (94) relay must be verified every 12 years
- The unmonitored trip circuit between the lock-out (86) (or auxiliary (94)) relay and the non-BES breaker does not have to be proven with an electrical trip
- In the case where there is no lockout (86) or auxiliary (94) tripping relay used, the trip circuit to the non-BES breaker does not have to be proven with an electrical trip.
- The trip coil of the non-BES circuit breaker does not have to be individually proven with an electrical trip

Example 3: A Generator Owner may have an non-BES circuit breaker that is tripped via a Protection System to which ~~PRC-005-3~~PRC-005-4 applies, such as the generator field breaker and low-side breakers on station service/excitation transformers connected to the generator bus.

Trip testing of the generator field breaker and low side station service/excitation transformer breaker(s) via lockout or auxiliary tripping relays are not required since these breakers may be associated with radially fed loads and are not considered to be BES breakers. An example of an otherwise non-BES circuit breaker that is tripped via a BES protection component might be (but is not limited to) a 6.9kV station service transformer source circuit breaker but has a trip that originates from a generator differential (87) relay.

- The differential relay must be verified.
- The current signals to the relay must be verified.
- All of the relevant dc supply tests still apply.
- The unmonitored trip circuit between the relay and any lock-out or auxiliary relay must be verified every 12 years.
- The unmonitored trip circuit between the lock-out (or auxiliary relay) and the non-BES breaker does not have to be proven with an electrical trip.
- In the case where there is no lock-out or auxiliary tripping relay used, the trip circuit to the non-BES breaker does not have to be proven with an electrical trip.
- The trip coil of the non-BES circuit breaker does not have to be individually proven with an electrical trip.

However, it is very prudent to verify the tripping of such breakers for the integrity of the overall generation plant.

Do I have to verify operation of breaker "a" contacts or any other normally closed auxiliary contacts in the trip path of each breaker as part of my control circuit test?

Operation of normally-closed contacts does not have to be verified. Verification of the tripping paths is the requirement. The continuity of the normally closed contacts will be verified when the tripping path is verified.

15.4 Batteries and DC Supplies (Table 1-4)

The NERC definition of a Protection System is:

- Protective relays which respond to electrical quantities,
- Communications Systems necessary for correct operation of protective functions,
- Voltage and current sensing devices providing inputs to protective relays,
- Station dc supply associated with protective functions (including station batteries, battery chargers, and non-battery-based dc supply), and
- Control circuitry associated with protective functions through the trip coil(s) of the circuit breakers or other interrupting devices.

The station battery is not the only component that provides dc power to a Protection System. In the new definition for Protection System, "station batteries" are replaced with "station dc supply" to make the battery charger and dc producing stored energy devices (that are not a battery) part of the Protection System that must be maintained.

The PSMT SDT recognizes that there are several technological advances in equipment and testing procedures that allow the owner to choose how to verify that a battery string is free of open circuits. The term "continuity" was introduced into the standard to allow the owner to choose how to verify continuity of a battery set by various methods, and not to limit the owner to other conventional methods of showing continuity. Continuity, as used in Table 1-4 of the standard, refers to verifying that there is a continuous current path from the positive terminal of the station battery set to the negative terminal. Without verifying continuity of a station battery, there is no way to determine that the station battery is available to supply dc power to the station. An open battery string will be an unavailable power source in the event of loss of the battery charger.

Batteries cannot be a unique population segment of a Performance-Based Maintenance Program (PBM) because there are too many variables in the electrochemical process to completely isolate all of the performance-changing criteria necessary for using PBM on battery Systems. However, nothing precludes the use of a PBM process for any other part of a dc supply besides the batteries themselves.

15.4.1 Frequently Asked Questions:

What constitutes the station dc supply, as mentioned in the definition of Protective System?

The previous definition of Protection System includes batteries, but leaves out chargers. The latest definition includes chargers, as well as dc systems that do not utilize batteries. This revision of ~~PRC-005-3~~PRC-005-4 is intended to capture these devices that were not included under the previous definition. The station direct current (dc) supply normally consists of two components: the battery charger and the station battery itself. There are also emerging technologies that provide a source of dc supply that does not include either a battery or charger.

Battery Charger - The battery charger is supplied by an available ac source. At a minimum, the battery charger must be sized to charge the battery (after discharge) and supply the constant dc load. In many cases, it may be sized also to provide sufficient dc current to handle the higher energy requirements of tripping breakers and switches when actuated by the protective relays in the Protection System.

Station Battery - Station batteries provide the dc power required for tripping and for supplying normal dc power to the station in the event of loss of the battery charger. There are several technologies of battery that require unique forms of maintenance as established in Table 1-4.

Emerging Technologies - Station dc supplies are currently being developed that use other energy storage technologies besides the station battery to prevent loss of the station dc supply when ac power is lost. Maintenance of these station dc supplies will require different kinds of tests and inspections. Table 1-4 presents maintenance activities and maximum allowable testing intervals for these new station dc supply technologies. However, because these technologies are relatively new, the maintenance activities for these station dc supplies may change over time.

What did the PSMT SDT mean by "continuity" of the dc supply?

The PSMT SDT recognizes that there are several technological advances in equipment and testing procedures that allow the owner to choose how to verify that a battery string is free of open circuits. The term "continuity" was introduced into the standard to allow the owner to choose how to verify continuity (no open circuits) of a battery set by various methods, and not to limit the owner to other conventional methods of showing continuity – lack of an open circuit. Continuity, as used in Table 1-4 of the standard, refers to verifying that there is a continuous current path from the positive terminal of the station battery set to the negative terminal (no open circuit). Without verifying continuity of a station battery, there is no way to determine that the station battery is available to supply dc power to the station. Whether it is caused from an open cell or a bad external connection, an open battery string will be an unavailable power source in the event of loss of the battery charger.

The current path through a station battery from its positive to its negative connection to the dc control circuits is composed of two types of elements. These path elements are the electrochemical path through each of its cells and all of the internal and external metallic connections and terminations of the batteries in the battery set. If there is loss of continuity (an open circuit) in any part of the electrochemical or metallic path, the battery set will not be available for service. In the event of the loss of the ac source or battery charger, the battery must be capable of supplying dc current, both for continuous dc loads and for tripping breakers and switches. Without continuity, the battery cannot perform this function.

At generating stations and large transmission stations where battery chargers are capable of handling the maximum current required by the Protection System, there are still problems that could potentially occur when the continuity through the connected battery is interrupted.

- Many battery chargers produce harmonics which can cause failure of dc power supplies in microprocessor-based protective relays and other electronic devices connected to station dc supply. In these cases, the substation battery serves as a filter for these harmonics. With the loss of continuity in the battery, the filter provided by the battery is no longer present.

- Loss of electrical continuity of the station battery will cause, in most battery chargers, regardless of the battery charger's output current capability, a delayed response in full output current from the charger. Almost all chargers have an intentional one- to two-second delay to switch from a low substation dc load current to the maximum output of the charger. This delay would cause the opening of circuit breakers to be delayed, which could violate system performance standards.

Monitoring of the station dc supply voltage will not indicate that there is a problem with the dc current path through the battery, unless the battery charger is taken out of service. At that time, a break in the continuity of the station battery current path will be revealed because there will be no voltage on the station dc circuitry. This particular test method, while proving battery continuity, may not be acceptable to all installations.

Although the standard prescribes what must be accomplished during the maintenance activity, it does not prescribe how the maintenance activity should be accomplished. There are several methods that can be used to verify the electrical continuity of the battery. These are not the only possible methods, simply a sampling of some methods:

- One method is to measure that there is current flowing through the battery itself by a simple clamp on milliamp-range ammeter. A battery is always either charging or discharging. Even when a battery is charged, there is still a measurable float charge current that can be detected to verify that there is continuity in the electrical path through the battery.
- A simple test for continuity is to remove the battery charger from service and verify that the battery provides voltage and current to the dc system. However, the behavior ofthe various dc-supplied equipment in the station should be considered before using this approach.
- Manufacturers of microprocessor-controlled battery chargers have developed methods for their equipment to periodically (or continuously) test for battery continuity. For example, one manufacturer periodically reduces the float voltage on the battery until current from the battery to the dc load can be measured to confirm continuity.
- Applying test current (as in some ohmic testing devices, or devices for locating dc grounds) will provide a current that when measured elsewhere in the string, will prove that the circuit is continuous.
- Internal ohmic measurements of the cells and units of lead-acid batteries (VRLA & VLA) can detect lack of continuity within the cells of a battery string; and when used in conjunction with resistance measurements of the battery's external connections, can prove continuity. Also some methods of taking internal ohmic measurements, by their very nature, can prove the continuity of a battery string without having to use the results of resistance measurements of the external connections.
- Specific gravity tests could infer continuity because without continuity there could be no charging occurring; and if there is no charging, then specific gravity will go down below acceptable levels over time.

No matter how the electrical continuity of a battery set is verified, it is a necessary maintenance activity that must be performed at the intervals prescribed by Table 1-4 to insure that the station dc supply has a path that can provide the required current to the Protection System at all times.

When should I check the station batteries to see if they have sufficient energy to perform as manufactured?

The answer to this question depends on the type of battery (valve-regulated lead-acid, vented lead-acid, or nickel-cadmium) and the maintenance activity chosen.

For example, if you have a valve-regulated lead-acid (VRLA) station battery, and you have chosen to evaluate the measured cell/unit internal ohmic values to the battery cell's baseline, you will have to perform verification at a maximum maintenance interval of no greater than every six months. While this interval might seem to be quite short, keep in mind that the six-month interval is important for VRLA batteries; this interval provides an accumulation of data that better shows when a VRLA battery is incapable of performing as manufactured.

If, for a VRLA station battery, you choose to conduct a performance capacity test on the entire station battery as the maintenance activity, then you will have to perform verification at a maximum maintenance interval of no greater than every three calendar years.

How is a baseline established for cell/unit internal ohmic measurements?

Establishment of cell/unit internal ohmic baseline measurements should be completed when lead-acid batteries are newly installed. To ensure that the baseline ohmic cell/unit values are most indicative of the station battery's ability to perform as manufactured, they should be made at some point in time after the installation to allow the cell chemistry to stabilize after the initial freshening charge. An accepted industry practice for establishing baseline values is after six-months of installation, with the battery fully charged and in service. However, it is recommended that each owner, when establishing a baseline, should consult the battery manufacturer for specific instructions on establishing an ohmic baseline for their product, if available.

When internal ohmic measurements are taken, the same make/model test equipment should be used to establish the baseline and used for the future trending of the cells internal ohmic measurements because of variances in test equipment and the type of ohmic measurement used by different manufacturer's equipment. Keep in mind that one manufacturer's "Conductance" test equipment does not produce similar results as another manufacturer's "Conductance" test equipment, even though both manufacturers have produced "Ohmic" test equipment. Therefore, for meaningful results to an established baseline, the same make/model of instrument should be used.

For all new installations of valve-regulated lead-acid (VRLA) batteries and vented lead-acid (VLA) batteries, where trending of the cells internal ohmic measurements to a baseline are to be used to determine the ability of the station battery to perform as manufactured, the establishment of the baseline, as described above, should be followed at the time of installation to insure the most accurate trending of the cell/unit. However, often for older VRLA batteries, the owners of the station batteries have not established a baseline at installation. Also for owners of VLA batteries who want to establish a maintenance activity which requires trending of measured ohmic values to a baseline, there was typically no baseline established at installation of the station battery to trend to.

To resolve the problem of the unavailability of baseline internal ohmic measurements for the individual cell/unit of a station battery, many manufacturers of internal ohmic measurement devices have established libraries of baseline values for VRLA and VLA batteries using their testing device. Also, several of the battery manufacturers have libraries of baselines for their products that can be used to trend to. However, it is important that when using battery manufacturer-supplied data that it is verified that the baseline readings to be used were taken with the same ohmic testing device that will be used for future measurements (for example "Conductance Readings" from one manufacturer's test equipment do not correlate to "Impedance Readings" from a different manufacturer's test equipment). Although many manufacturers may have provided baseline values, which will allow trending of the internal ohmic measurements over the remaining life of a station battery, these baselines are not the actual cell/unit measurements for the battery being trended. It is important to have a baseline tailored to the station battery to more accurately use the tool of ohmic measurement trending. That more customized baseline can only be created by following the establishment of a baseline for each cell/unit at the time of installation of the station battery.

Why determine the State of Charge?

Even though there is no present requirement to check the state of charge of a battery, it can be a very useful tool in determining the overall condition of a battery system. The following discussions are offered as a general reference.

When a battery is fully charged, the battery is available to deliver its existing capacity. As a battery is discharged, its ability to deliver its maximum available capacity is diminished. It is necessary to determine if the state of charge has dropped to an unacceptable level.

What is State of Charge and how can it be determined in a station battery?

The state of charge of a battery refers to the ratio of residual capacity at a given instant to the maximum capacity available from the battery. When a battery is fully charged, the battery is available to deliver its existing capacity. As a battery is discharged, its ability to deliver its maximum available capacity is diminished. Knowing the amount of energy left in a battery compared with the energy it had when it was fully charged gives the user an indication of how much longer a battery will continue to perform before it needs recharging.

For vented lead-acid (VLA) batteries which use accessible liquid electrolyte, a hydrometer can be used to test the specific gravity of each cell as a measure of its state of charge. The hydrometer depends on measuring changes in the weight of the active chemicals. As the battery discharges, the active electrolyte, sulfuric acid, is consumed and the concentration of the sulfuric acid in water is reduced. This, in turn, reduces the specific gravity of the solution in direct proportion to the state of charge. The actual specific gravity of the electrolyte can, therefore, be used as an indication of the state of charge of the battery. Hydrometer readings may not tell the whole story, as it takes a while for the acid to get mixed up in the cells of a VLA battery. If measured right after charging, you might see high specific gravity readings at the top of the cell, even though it is much less at the bottom. Conversely, if taken shortly after adding water to the cell, the specific gravity readings near the top of the cell will be lower than those at the bottom.

Nickel-cadmium batteries, where the specific gravity of the electrolyte does not change during battery charge and discharge, and valve-regulated lead-acid (VRLA) batteries, where the electrolyte is not accessible, cannot have their state of charge determined by specific gravity readings. For these two types of batteries, and for VLA batteries also, where another method besides taking hydrometer readings is desired, the state of charge may be determined by taking voltage and current readings at the battery terminals. The methods employed to obtain accurate readings vary for the different battery types. Manufacturers' information and IEEE guidelines can be consulted for specifics; (see IEEE 1106 Annex B for Nickel Cadmium batteries, IEEE 1188 Annex A for VRLA batteries and IEEE 450 for VLA batteries.

Why determine the Connection Resistance?

High connection resistance can cause abnormal voltage drop or excessive heating during discharge of a station battery. During periods of a high rate of discharge of the station battery, a very high resistance can cause severe damage. The maintenance requirement to verify battery terminal connection resistance in Table 1-4 is established to verify that the integrity of all battery electrical connections is acceptable. This verification includes cell-to-cell (intercell) and external circuit terminations. Your method of checking for acceptable values of intercell and terminal connection resistance could be by individual readings, or a combination of the two. There are test methods presently that can read post termination resistances and resistance values between external posts. There are also test methods presently available that take a combination reading of the post termination connection resistance plus the intercell resistance value plus the post termination connection resistance value. Either of the two methods, or any other method, that can show if the adequacy of connections at the battery posts is acceptable.

Adequacy of the electrical terminations can be determined by comparing resistance measurements for all connections taken at the time of station battery's installation to the same resistance measurements taken at the maintenance interval chosen, not to exceed the maximum maintenance interval of Table 1-4. Trending of the interval measurements to the baseline measurements will identify any degradation in the battery connections. When the connection resistance values exceed the acceptance criteria for the connection, the connection is typically disassembled, cleaned, reassembled and measurements taken to verify that the measurements are adequate when compared to the baseline readings.

What conditions should be inspected for visible battery cells?

The maintenance requirement to inspect the cell condition of all station battery cells where the cells are visible is a maintenance requirement of Table 1-4. Station batteries are different from any other component in the Protection Station because they are a perishable product due to the electrochemical process which is used to produce dc electrical current and voltage. This inspection is a detailed visual inspection of the cells for abnormalities that occur in the aging process of the cell. In VLA battery visual inspections, some of the things that the inspector is typically looking for on the plates are signs of sulfation of the plates, abnormal colors (which are an indicator of sulfation or possible copper contamination) and abnormal conditions such as cracked grids. The visual inspection could look for symptoms of hydration that would indicate that the battery has been left in a completely discharged state for a prolonged period. Besides looking at the plates for signs of aging, all internal connections, such as the bus bar connection to each plate, and the connections to all posts of the battery need to be visually inspected for abnormalities. In a complete visual inspection for the condition of the cell the cell plates, separators and sediment space of each cell must be looked at for signs of deterioration. An inspection of the station battery's cell condition also includes looking at all terminal posts and cell-to-cell electric connections to ensure they are corrosion free. The case of the battery containing the cell, or cells, must be inspected for cracks and electrolyte leaks through cracks and the post seals.

This maintenance activity cannot be extended beyond the maximum maintenance interval of Table 1-4 by a Performance-Based Maintenance Program (PBM) because of the electrochemical aging process of the station battery, nor can there be any monitoring associated with it because there must be a visual inspection involved in the activity. A remote visual inspection could possibly be done, but its interval must be no greater than the maximum maintenance interval of Table 1-4.

Why is it necessary to verify the battery string can perform as manufactured? I only care that the battery can trip the breaker, which means that the battery can perform as designed. I oversize my batteries so that even if the battery cannot perform as manufactured, it can still trip my breakers.

The fundamental answer to this question revolves around the concept of battery performance "as designed" vs. battery performance "as manufactured." The purpose of the various sections of Table 1-4 of this standard is to establish requirements for the Protection System owner to maintain the batteries, to ensure they will operate the equipment when there is an incident that requires dc power, and ensure the batteries will continue to provide adequate service until at least the next maintenance interval. To meet these goals, the correct battery has to be properly selected to meet the design parameters, and the battery has to deliver the power it was manufactured to provide.

When testing batteries, it may be difficult to determine the original design (i.e., load profile) of the dc system. This standard is not intended as a design document, and requirements relating to design are, therefore, not included.

Where the dc load profile is known, the best way to determine if the system will operate as designed is to conduct a service test on the battery. However, a service test alone might not fully determine if the battery is healthy. A battery with 50% capacity may be able to pass a service test, but the battery would be in a serious state of deterioration and could fail at some point in the near future.

To ensure that the battery will meet the required load profile and continue to meet the load profile until the next maintenance interval, the installed battery must be sized correctly (i.e., a correct design), and it must be in a good state of health. Since the design of the dc system is not within the scope of the standard, the only consistent and reliable method to ensure that the battery is in a good state of health is to confirm that it can perform as manufactured. If the battery can perform as manufactured and it has been designed properly, the system should operate properly until the next maintenance interval.

How do I verify the battery string can perform as manufactured?

Optimally, actual battery performance should be verified against the manufacturer's rating curves. The best practice for evaluating battery performance is via a performance test. However, due to both logistical and system reliability concerns, some Protection System owners prefer other methods to determine if a battery can perform as manufactured. There are several battery parameters that can be evaluated to determine if a battery can perform as manufactured. Ohmic measurements and float current are two examples of parameters that have been reported to assist in determining if a battery string can perform as manufactured.

The evaluation of battery parameters in determining battery health is a complex issue, and is not an exact science. This standard gives the user an opportunity to utilize other measured parameters to determine if the battery can perform as manufactured. It is the responsibility of

the Protection System owner, however, to maintain a documented process that demonstrates the chosen parameter(s) and associated methodology used to determine if the battery string can perform as manufactured.

Whatever parameters are used to evaluate the battery (ohmic measurements, float current, float voltages, temperature, specific gravity, performance test, or combination thereof), the goal is to determine the value of the measurement (or the percentage change) at which the battery fails to perform as manufactured, or the point where the battery is deteriorating so rapidly that it will not perform as manufactured before the next maintenance interval.

This necessitates the need for establishing and documenting a baseline. A baseline may be required of every individual cell, a particular battery installation, or a specific make, model, or size of a cell. Given a consistent cell manufacturing process, it may be possible to establish a baseline number for the cell (make/model/type) and, therefore, a subsequent baseline for every installation would not be necessary. However, future installations of the same battery types should be spot-checked to ensure that your baseline remains applicable.

Consistent testing methods by trained personnel are essential. Moreover, it is essential that these technicians utilize the same make/model of ohmic test equipment each time readings are taken in order to establish a meaningful and accurate trendline against the established baseline. The type of probe and its location (post, connector, etc) for the reading need to be the same for each subsequent test. The room temperature should be recorded with the readings for each test as well. Care should be taken to consider any factors that might lead a trending program to become invalid.

Float current along with other measureable parameters can be used in lieu of or in concert with ohmic measurement testing to measure the ability of a battery to perform as manufactured. The key to using any of these measurement parameters is to establish a baseline and the point where the reading indicates that the battery will not perform as manufactured.

The establishment of a baseline may be different for various types of cells and for different types of installations. In some cases, it may be possible to obtain a baseline number from the battery manufacturer, although it is much more likely that the baseline will have to be established after the installation is complete. To some degree, the battery may still be “forming” after installation; consequently, determining a stable baseline may not be possible until several months after the battery has been in service.

The most important part of this process is to determine the point where the ohmic reading (or other measured parameter(s)) indicates that the battery cannot perform as manufactured. That point could be an absolute number, an absolute change, or a percentage change of an established baseline.

Since there are no universally-accepted repositories of this information, the Protection System owner will have to determine the value/percentage where the battery cannot perform as manufactured (heretofore referred to as a failed cell). This is the most difficult and important part of the entire process.

To determine the point where the battery fails to perform as manufactured, it is helpful to have a history of a battery type, if the data includes the parameter(s) used to evaluate the battery's ability to perform as manufactured against the actual demonstrated performance/capacity of a battery/cell.

For example, when an ohmic reading has been recorded that the user suspects is indicating a failed cell, a performance test of that cell (or string) should be conducted in order to prove/quantify that the cell has failed. Through this process, the user needs to determine the ohmic value at which the performance of the cell has dropped below 80% of the manufactured, rated performance. It is likely that there may be a variation in ohmic readings that indicates a failed cell (possibly significant). It is prudent to use the most conservative values to determine the point at which the cell should be marked for replacement. Periodically, the user should demonstrate that an “adequate” ohmic reading equates to an adequate battery performance (>80% of capacity).

Similarly, acceptance criteria for "good" and "failed" cells should be established for other parameters such as float current, specific gravity, etc., if used to determine the ability of a battery to function as designed.

What happens if I change the make/model of ohmic test equipment after the battery has been installed for a period of time?

If a user decides to switch testers, either voluntarily or because the equipment is not supported/sold any longer, the user may have to establish a new base line and new parameters that indicate when the battery no longer performs as manufactured. The user always has a choice to perform a capacity test in lieu of establishing new parameters.

What are some of the differences between lead-acid and nickel-cadmium batteries?

There is a marked difference in the aging process of lead acid and nickel-cadmium station batteries. The difference in the aging process of these two types of batteries is chiefly due to the electrochemical process of the battery type. Aging and eventual failure of lead acid batteries is due to expansion and corrosion of the positive grid structure, loss of positive plate active material, and loss of capacity caused by physical changes in the active material of the positive plates. In contrast, the primary failure of nickel-cadmium batteries is due to the gradual linear aging of the active materials in the plates. The electrolyte of a nickel-cadmium battery only facilitates the chemical reaction (it functions only to transfer ions between the positive and negative plates), but is not chemically altered during the process like the electrolyte of a lead acid battery. A lead acid battery experiences continued corrosion of the positive plate and grid structure throughout its operational life while a nickel-cadmium battery does not.

Changes to the properties of a lead acid battery when periodically measured and trended to a baseline, can indicate aging of the grid structure, positive plate deterioration, or changes in the active materials in the plate.

Because of the clear differences in the aging process of lead acid and nickel-cadmium batteries, there are no significantly measurable properties of the nickel-cadmium battery that can be measured at a periodic interval and trended to determine aging. For this reason, Table 1-4(c) (Protection System Station dc supply Using nickel-cadmium [NiCad] Batteries) only specifies one minimum maintenance activity and associated maximum maintenance interval necessary to verify that the station battery can perform as manufactured by evaluating cell/unit measurements indicative of battery performance against the station battery baseline. This maintenance activity is to conduct a performance or modified performance capacity test of the entire battery bank.

Why in Table 1-4 of ~~PRC-005-3~~PRC-005-4 is there a maintenance activity to inspect the structural intergrity of the battery rack?

The purpose of this inspection is to verify that the battery rack is correctly installed and has no deterioration that could weaken its structural integrity.
Because the battery rack is specifically manufactured for the battery that is mounted on it, weakening of its structural members by rust or corrosion can physically jeopardize the battery.

What is required to comply with the "Unintentional dc Grounds" requirement?

In most cases, the first ground that appears on a battery is not a problem. It is the unintentional ground that appears on the opposite pole that becomes problematic. Even then many systems are designed to operate favorably under some unintentional DC ground situations. It is up to the owner of the Protection System to determine if corrective actions are needed on detected unintentional DC grounds. The standard merely requires that a check be made for the existence of Unintentional DC Grounds. Obviously, a "check-off" of some sort will have to be devised by the inspecting entity to document that a check is routinely done for Unintentional DC Grounds because of the possible consequences to the Protection System.

Where the standard refers to "all cells," is it sufficient to have a documentation method that refers to "all cells," or do we need to have separate documentation for every cell? For example, do I need 60 individual documented check-offs for good electrolyte level, or would a single check-off per bank be sufficient?

A single check-off per battery bank is sufficient for documentation, as long as the single check-off attests to checking all cells/units.

Does this standard refer to Station batteries or all batteries; for example, Communications Site Batteries?

This standard refers to Station Batteries. The drafting team does not believe that the scope of this standard refers to communications sites. The batteries covered under ~~PRC-005-3~~PRC-005-4 are the batteries that supply the trip current to the trip coils of the interrupting devices that are a part of the Protection System. The SDT believes that a loss of power to the communications systems at a remote site would cause the communications systems associated with protective relays to alarm at the substation. At this point, the corrective actions can be initiated.

What are cell/unit internal ohmic measurements?

With the introduction of Valve-Regulated Lead-Acid (VRLA) batteries to station dc supplies in the 1980's several of the standard maintenance tools that are used on Vented Lead-Acid (VLA) batteries were unable to be used on this new type of lead-acid battery to determine its state of health. The only tools that were available to give indication of the health of these new VRLA batteries were voltage readings of the total battery voltage, the voltage of the individual cells and periodic discharge tests.

In the search for a tool for determining the health of a VRLA battery several manufacturers studied the electrical model of a lead acid battery's current path through its cell. The overall battery current path consists of resistance and inductive and capacitive reactance. The inductive reactance in the current path through the battery is so minuscule when compared to the huge capacitive reactance of the cells that it is often ignored in most circuit models of the battery cell. Taking the basic model of a battery cell manufacturers of battery test equipment have developed and marketed testing devices to take measurements of the current path to detect degradation in the internal path through the cell.

In the battery industry, these various types of measurements are referred to as ohmic measurements. Terms used by the industry to describe ohmic measurements are ac conductance, ac impedance, and dc resistance. They are defined by the test equipment providers and IEEE and refer to the method of taking ohmic measurements of a lead acid battery. For example, in one manufacturer's ac conductance equipment measurements are taken by applying a voltage of a known frequency and amplitude across a cell or battery unit and observing the ac current flow it produces in response to the voltage. A manufacturer of an ac impedance meter measures ac current of a known frequency and amplitude that is passed through the whole battery string and determines the impedances of each cell or unit by measuring the resultant ac voltage drop across them. On the other hand, dc resistance of a cell is measured by a third manufacturer's equipment by applying a dc load across the cell or unit and measuring the step change in both the voltage and current to calculate the internal dc resistance of the cell or unit.

It is important to note that because of the rapid development of the market for ohmic measurement devices, there were no standards developed or used to mandate the test signals used in making ohmic measurements. Manufacturers using proprietary methods and applying different frequencies and magnitudes for their signals have developed a diversity of measurement devices. This diversity in test signals coupled with the three different types of ohmic measurements techniques (impedance conductance and resistance) make it impossible to always get the same ohmic measurement for a cell with different ohmic measurement devices. However, IEEE has recognized the great value for choosing one device for ohmic measurement, no matter who makes it or the method to calculate the ohmic measurement. The only caution given by IEEE and the battery manufacturers is that when trending the cells of a lead acid station battery consistent ohmic measurement devices should be used to establish the baseline measurement and to trend the battery set for its entire life.

For VRLA batteries both IEEE Standard 1188 (Maintenance, Testing and Replacement of VRLA Batteries) and IEEE Standard 1187 (Installation Design and Installation of VRLA Batteries) recognize the importance of the maintenance activity of establishing a baseline for "cell/unit internal ohmic measurements (impedance, conductance and resistance)" and trending them at frequent intervals over the life of the battery. There are extensive discussions about the need for taking these measurements in these standards. IEEE Standard 1188 requires taking internal ohmic values as described in Annex C4 during regular inspections of the station battery. For VRLA batteries IEEE Standard 1188 in talking about the necessity of establishing a baseline and trending it over time says, "…depending on the degree of change a performance test, cell replacement or other corrective action may be necessary…" (IEEE std 1188-2005, C.4 page 18).

For VLA batteries IEEE Standard 484 (Installation of VLA batteries) gives several guidelines about establishing baseline measurements on newly installed lead acid stationary batteries. The standard also discusses the need to look for significant changes in the ohmic measurements, the caution that measurement data will differ with each type of model of instrument used, and lists a number of factors that affect ohmic measurements.

At the beginning of the 21st century, EPRI conducted a series of extensive studies to determine the relationship of internal ohmic measurements to the capacity of a lead acid battery cell. The studies indicated that internal ohmic measurements were in fact a good indicator of a lead acid battery cell's capacity, but because users often were only interested in the total station battery capacity and the technology does not precisely predict overall battery capacity, if a user only needs “an accurate measure of the overall battery capacity,” they should “perform a battery capacity test.”

Prior to the EPRI studies some large and small companies which owned and maintained station dc supplies in NERC Protection Systems developed maintenance programs where trending of ohmic measurements of cells/units of the station’s battery became the maintenance activity for determining if the station battery could perform as manufactured. By evaluation of the trending of the ohmic measurements over time, the owner could track the performance of the individual components of the station battery and determine if a total station battery or components of it required capacity testing, removal, replacement or in many instances replacement of the entire station battery. By taking this condition based approach these owners have eliminated having to perform capacity testing at prescribed intervals to determine if a battery needs to be replaced and are still able to effectively determine if a station battery can perform as manufactured.

My VRLA batteries have multiple-cells within an individual battery jar (or unit); how am I expected to comply with the cell-to-cell ohmic measurement requirements on these units that I cannot get to?

Measurement of cell/unit (not all batteries allow access to “individual cells” some “units” or jars may have multiple cells within a jar) internal ohmic values of all types of lead acid batteries where the cells of the battery are not visible is a station dc supply maintenance activity in Table 1-4. In cases where individual cells in a multi-cell unit are inaccessible, an ohmic measurement of the entire unit may be made.

I have a concern about my batteries being used to support additional auxiliary loads beyond my protection control systems in a generation station. Is ohmic measurement testing sufficient for my needs?

While this standard is focused on addressing requirements for Protection Systems, if batteries are used to service other load requirements beyond that of Protection Systems (e.g. pumps, valves, inverter loads), the functional entity may consider additional testing to confirm that the capacity of the battery is sufficient to support all loads.

Why verify voltage?

There are two required maintenance activities associated with verification of dc voltages in Table 1-4. These two required activities are to verify station dc supply voltage and float voltage of the battery charger, and have different maximum maintenance intervals. Both of these voltage verification requirements relate directly to the battery charger maintenance.

The verification of the dc supply voltage is simply an observation of battery voltage to prove that the charger has not been lost or is not malfunctioning; a reading taken from the battery charger panel meter or even SCADA values of the dc voltage could be some of the ways that one could satisfy the requirements. Low battery voltage below float voltage indicates that the battery may be on discharge and, if not corrected, the station battery could discharge down to some extremely low value that will not operate the Protection System. High voltage, close to or above the maximum allowable dc voltage for equipment connected to the station dc supply indicates the battery charger may be malfunctioning by producing high dc voltage levels on the Protection System. If corrective actions are not taken to bring the high voltage down, the dc power supplies and other electronic devices connected to the station dc supply may be damaged. The maintenance activity of verifying the float voltage of the battery charger is not to prove that a charger is lost or producing high voltages on the station dc supply, but rather to prove that the charger is properly floating the battery within the proper voltage limits. As above, there are many ways that this requirement can be met.

Why check for the electrolyte level?

In vented lead-acid (VLA) and nickel-cadmium (NiCad) batteries the visible electrolyte level must be checked as one of the required maintenance activities that must be performed at an interval that is equal to or less than the maximum maintenance interval of Table 1-4. Because the electrolyte level in valve-regulated lead-acid (VRLA) batteries cannot be observed, there is no maintenance activity listed in Table 1-4 of the standard for checking the electrolyte level. Low electrolyte level of any cell of a VLA or NiCad station battery is a condition requiring correction. Typically, the electrolyte level should be returned to an acceptable level for both types of batteries (VLA and NiCad) by adding distilled or other approved-quality water to the cell.

Often people confuse the interval for watering all cells required due to evaporation of the electrolyte in the station battery cells with the maximum maintenance interval required to check the electrolyte level. In many of the modern station batteries, the jar containing the electrolyte is so large with the band between the high and low electrolyte level so wide that normal evaporation which would require periodic watering of all cells takes several years to occur. However, because loss of electrolyte due to cracks in the jar, overcharging of the station battery, or other unforeseen events can cause rapid loss of electrolyte; the shorter maximum maintenance intervals for checking the electrolyte level are required. A low level of electrolyte in a VLA battery cell which exposes the tops of the plates can cause the exposed portion of the plates to accelerated sulfation resulting in loss of cell capacity. Also, in a VLA battery where the electrolyte level goes below the end of the cell withdrawal tube or filling funnel, gasses can exit the cell by the tube instead of the flame arrester and present an explosion hazard.

What are the parameters that can be evaluated in Tables 1-4(a) and 1-4(b)?

The most common parameter that is periodically trended and evaluated by industry today to verify that the station battery can perform as manufactured is internal ohmic cell/unit measurements.

In the mid 1990s, several large and small utilities began developing maintenance and testing programs for Protection System station batteries using a condition based maintenance approach of trending internal ohmic measurements to each station battery cell's baseline value. Battery owners use the data collected from this maintenance activity to determine (1) when a station battery requires a capacity test (instead of performing a capacity test on a predetermined, prescribed interval), (2) when an individual cell or battery unit should be replaced, or (3) based on the analysis of the trended data, if the station battery should be replaced without performing a capacity test.

Other examples of measurable parameters that can be periodically trended and evaluated for lead acid batteries are cell voltage, float current, connection resistance. However, periodically trending and evaluating cell/unit Ohmic measurements are the most common battery/cell parameters that are evaluated by industry to verify a lead acid battery string can perform as manufactured.

Why does it appear that there are two maintenance activities in Table 1-4(b) (for VRLA batteries) that appear to be the same activity and have the same maximum maintenance interval?

There are two different and distinct reasons for doing almost the same maintenance activity at the same interval for valve-regulated lead-acid (VRLA) batteries. The first similar activity for VRLA batteries (Table 1-4(b)) that has the same maximum maintenance interval is to "measure battery cell/unit internal ohmic values." Part of the reason for this activity is because the visual inspection of the cell condition is unavailable for VRLA batteries. Besides the requirement to measure the internal ohmic measurements of VRLA batteries to determine the internal health of the cell, the maximum maintenance interval for this activity is significantly shorter than the interval for vented lead-acid (VLA) due to some unique failure modes for VRLA batteries. Some of the potential problems that VRLA batteries are susceptible to that do not affect VLA batteries are thermal runaway, cell dry-out, and cell reversal when one cell has a very low capacity.

The other similar activity listed in Table 1-4(b) is "…verify that the station battery can perform as manufactured by evaluating the measured cell/unit measurements indicative of battery performance (e.g. internal ohmic values) against the station battery baseline." This activity allows an owner the option to choose between this activity with its much shorter maximum maintenance interval or the longer maximum maintenance interval for the maintenance activity to "Verify that the station battery can perform as manufactured by conducting a performance or modified performance capacity test of the entire battery bank."

For VRLA batteries, there are two drivers for internal ohmic readings. The first driver is for a means to trend battery life. Trending against the baseline of VRLA cells in a battery string is essential to determine the approximate state of health of the battery. Ohmic measurement testing may be used as the mechanism for measuring the battery cells. If all the cells in the string exhibit a consistent trend line and that trend line has not risen above a specific deviation (e.g. 30%) over baseline for impedance tests or below baseline for conductance tests, then a judgment can be made that the battery is still in a reasonably good state of health and able to 'perform as manufactured.' It is essential that the specific deviation mentioned above is based on data (test or otherwise) that correlates the ohmic readings for a specific battery/tester combination to the health of the battery. This is the intent of the "perform **as** manufactured six-month test" at Row 4 on Table 1-4b.

The second big driver is VRLA batteries tendency for thermal runaway. This is the intent of the "thermal runaway test" at Row 2 on Table 1-4b. In order to detect a cell in thermal runaway, you need not necessarily have a formal trending program. When a single cell/unit changes significantly or significantly varies from the other cells (e.g. a doubling of resistance/impedance or a 50% decrease in conductance), there is a high probability that the cell/unit/string needs to be replaced as soon as possible. In other words, if the battery is 10 years old and all the cells have approached a significant change in ohmic values over baseline, then you have a battery which is approaching end of life. You need to get ready to buy a new battery, but you do not have to worry about an impending catastrophic failure. On the other hand, if the battery is five years old and you have one cell that has a markedly different ohmic reading than all the other cells, then you need to be worried that this cell is susceptible to thermal runaway. If the float (charging) current has risen significantly and the ohmic measurement has increased/decreased as described above then concern of catastrophic failure should trigger attention for corrective action.

If an entity elects to use a capacity test rather than a cell ohmic value trending program, this does not eliminate the need to be concerned about thermal runaway – the entity still needs to do the six-month readings and look for cells which are outliers in the string but they need not trend results against the factory/as new baseline. Some entities will not mind the extra administrative burden of having the ongoing trending program against baseline - others would rather just do the capacity test and not have to trend the data against baseline. Nonetheless, all entities must look for ohmic outliers on a six-month basis.

It is possible to accomplish both tasks listed (trend testing for capability and testing for thermal runaway candidates) with the very same ohmic test. It becomes an analysis exercise of watching the trend from baselines and watching for the oblique cell measurement.

In table 1-4(f) (Exclusions for Protection System Station dc Supply Monitoring Devices and Systems), must all component attributes listed in the table be met before an exclusion can be granted for a maintenance activity?

Table 1-4(f) was created by the drafting team to allow Protection System dc supply owners to obtain exclusions from periodic maintenance activities by using monitoring devices. The basis of the exclusions granted in the table is that the monitoring devices must incorporate the monitoring capability of microprocessor based components which perform continuous self-monitoring. For failure of the microprocessor device used in dc supply monitoring, the self checking routine in the microprocessor must generate an alarm which will be reported within 24 hours of device failure to a location where corrective action can be initiated.

Table 1-4(f) lists 8 component attributes along with a specific periodic maintenance activity associated with each of the 8 attributes listed. If an owner of a station dc supply wants to be excluded from periodically performing one of the 8 maintenance activities listed in table 1-4(f), the owner must have evidence that the monitoring and alarming component attributes associated with the excluded maintenance activity are met by the self checking microprocessor based device with the specific component attribute listed in the table 1-4(f).

For example if an owner of a VLA station battery does not want to "verify station dc supply voltage" every "4 calendar months" (see table 1-4(a)), the owner can install a monitoring and alarming device "with high and low voltage monitoring and alarming of the battery charger voltage to detect charger overvoltage and charger failure" and "no periodic verification of station dc supply voltage is required" (see table 1-4(f) first row). However, if for the same Protection System discussed above, the owner does not install "electrolyte level monitoring and alarming in every cell" and "unintentional dc ground monitoring and alarming" (see second and third rows of table 1-4(f)), the owner will have to "inspect electrolyte level and for unintentional grounds" every "4 calendar months" (see table 1-4(a)).

15.5 Associated communications equipment (Table 1-2)

The equipment used for tripping in a communications-assisted trip scheme is a vital piece of the trip circuit. Remote action causing a local trip can be thought of as another parallel trip path to the trip coil that must be tested. Besides the trip output and wiring to the trip coil(s), there is also a communications medium that must be maintained. Newer technologies now exist that achieve communications-assisted tripping without the conventional wiring practices of older technology. For example, older technologies may have included Frequency Shift Key methods. This technology requires that guard and trip levels be maintained. The actual tripping path(s) to the trip coil(s) may be tested as a parallel trip path within the dc control circuitry tests. Emerging technologies transfer digital information over a variety of carrier mediums that are then interpreted locally as trip signals. The requirements apply to the communicated signal needed for the proper operation of the protective relay trip logic or scheme. Therefore, this standard is applied to equipment used to convey both trip signals (permissive or direct) and block signals.

It was the intent of this standard to require that a test be performed on any communications-assisted trip scheme, regardless of the vintage of technology. The essential element is that the tripping (or blocking) occurs locally when the remote action has been asserted; or that the tripping (or blocking) occurs remotely when the local action is asserted. Note that the required testing can still be done within the concept of testing by overlapping segments. Associated communications equipment can be (but is not limited to) testing at other times and different frequencies as the protective relays, the individual trip paths and the affected circuit interrupting devices.

Some newer installations utilize digital signals over fiber-optics from the protective relays in the control house to the circuit interrupting device in the yard. This method of tripping the circuit breaker, even though it might be considered communications, must be maintained per the dc control circuitry maintenance requirements.

15.5.1 Frequently Asked Questions:

What are some examples of mechanisms to check communications equipment functioning?

For unmonitored Protection Systems, various types of communications systems will have different facilities for on-site integrity checking to be performed at least every four months during a substation visit. Some examples are, but not limited to:

- On-off power-line carrier systems can be checked by performing a manual carrier keying test between the line terminals, or carrier check-back test from one terminal.
- Systems which use frequency-shift communications with a continuous guard signal (over a telephone circuit, analog microwave system, etc.) can be checked by observing for a loss-of-guard indication or alarm. For frequency-shift power-line carrier systems, the guard signal level meter can also be checked.
- Hard-wired pilot wire line Protection Systems typically have pilot-wire monitoring relays that give an alarm indication for a pilot wire ground or open pilot wire circuit loop.
- Digital communications systems typically have a data reception indicator or data error indicator (based on loss of signal, bit error rate, or frame error checking).

For monitored Protection Systems, various types of communications systems will have different facilities for monitoring the presence of the communications channel, and activating alarms that can be monitored remotely. Some examples are, but not limited to:

- On-off power-line carrier systems can be shown to be operational by automated periodic power-line carrier check-back tests with remote alarming of failures.
- Systems which use a frequency-shift communications with a continuous guard signal (over a telephone circuit, analog microwave system, etc.) can be remotely monitored with a loss-of-guard alarm or low signal level alarm.
- Hard-wired pilot wire line Protection Systems can be monitored by remote alarming of pilot-wire monitoring relays.
- Digital communications systems can activate remotely monitored alarms for data reception loss or data error indications.
- Systems can be queried for the data error rates.

For the highest degree of monitoring of Protection Systems, the communications system must monitor all aspects of the performance and quality of the channel that show it meets the design performance criteria, including monitoring of the channel interface to protective relays.

- In many communications systems signal quality measurements, including signal-to-noise ratio, received signal level, reflected transmitter power or standing wave ratio, propagation delay, and data error rates are compared to alarm limits. These alarms are connected for remote monitoring.
- Alarms for inadequate performance are remotely monitored at all times, and the alarm communications system to the remote monitoring site must itself be continuously monitored to assure that the actual alarm status at the communications equipment location is continuously being reflected at the remote monitoring site.

What is needed for the four-month inspection of communications-assisted trip scheme equipment?

The four-month inspection applies to unmonitored equipment. An example of compliance with this requirement might be, but is not limited to:

With each site visit, check that the equipment is free from alarms; check any metered signal levels, and that power is still applied. While this might be explicit for a particular type of equipment (i.e., FSK equipment), the concept should be that the entity verify that the communications equipment that is used in a Protection System is operable through a cursory inspection and site visit. This site visit can be eliminated on this particular example if the FSK equipment had a monitored alarm on Loss of Guard. Blocking carrier systems with auto checkbacks will present an alarm when the channel fails allowing a visual indication. With no auto checkback, the channel integrity will need to be verified by a manual checkback or a two ended signal check. This check could also be eliminated by bring the auto checkback failure alarm to the monitored central location.

Does a fiber optic I/O scheme used for breaker tripping or control within a station, for example - transmitting a trip signal or control logic between the control house and the breaker control cabinet, constitute a communications system?

This equipment is presently classified as being part of the Protection System control circuitry and tested per the portions of Table 1 applicable to "Protection System Control Circuitry", rather than those portions of the table applicable to communications equipment.

What is meant by "Channel" and "Communications Systems" in Table 1-2?

The transmission of logic or data from a relay in one station to a relay in another station for use in a pilot relay scheme will require a communications system of some sort. Typical relay communications systems use fiber optics, leased audio channels, power line carrier, and microwave. The overall communications system includes the channel and the associated communications equipment.

This standard refers to the "channel" as the medium between the transmitters and receivers in the relay panels such as a leased audio or digital communications circuit, power line and power line carrier auxiliary equipment, and fiber. The dividing line between the channel and the associated communications equipment is different for each type of media.

Examples of the Channel:

- Power Line Carrier (PLC) - The PLC channel starts and ends at the PLC transmitter and receiver output unless there is an internal hybrid. The channel includes the external hybrids, tuners, wave traps and the power line itself.
- Microwave –The channel includes the microwave multiplexers, radios, antennae and associated auxiliary equipment. The audio tone and digital transmitters and receivers in the relay panel are the associated communications equipment.
- Digital/Audio Circuit – The channel includes the equipment within and between the substations. The associated communications equipment includes the relay panel transmitters and receivers and the interface equipment in the relays.

- Fiber Optic – The channel starts at the fiber optic connectors on the fiber distribution panel at the local station and goes to the fiber optic distribution panel at the remote substation. The jumpers that connect the relaying equipment to the fiber distribution panel and any optical-electrical signal format converters are the associated communications equipment

Figure 1-2, A-1 and A-2 at the end of this document show good examples of the communications channel and the associated communications equipment.

In Table 1-2, the Maintenance Activities section of the Protection System Communications Equipment and Channels refers to the quality of the channel meeting "performance criteria." What is meant by performance criteria?

Protection System communications channels must have a means of determining if the channel and communications equipment is operating normally. If the channel is not operating normally, an alarm will be indicated. For unmonitored systems, this alarm will probably be on the panel. For monitored systems, the alarm will be transmitted to a remote location.

Each entity will have established a nominal performance level for each Protection System communications channel that is consistent with proper functioning of the Protection System. If that level of nominal performance is not being met, the system will go into alarm. Following are some examples of Protection System communications channel performance measuring:

- For direct transfer trip using a frequency shift power line carrier channel, a guard level monitor is part of the equipment. A normal receive level is established when the system is calibrated and if the signal level drops below an established level, the system will indicate an alarm.
- An on-off blocking signal over power line carrier is used for directional comparison blocking schemes on transmission lines. During a Fault, block logic is sent to the remote relays by turning on a local transmitter and sending the signal over the power line to a receiver at the remote end. This signal is normally off so continuous levels cannot be checked. These schemes use check-back testing to determine channel performance. A predetermined signal sequence is sent to the remote end and the remote end decodes this signal and sends a signal sequence back. If the sending end receives the correct information from the remote terminal, the test passes and no alarm is indicated. Full power and reduced power tests are typically run. Power levels for these tests are determined at the time of calibration.
- Pilot wire relay systems use a hardwire communications circuit to communicate between the local and remote ends of the protective zone. This circuit is monitored by circulating a dc current between the relay systems. A typical level may be 1 mA. If the level drops below the setting of the alarm monitor, the system will indicate an alarm.
- Modern digital relay systems use data communications to transmit relay information to the remote end relays. An example of this is a line current differential scheme commonly used on transmission lines. The protective relays communicate current magnitude and phase information over the communications path to determine if the Fault is located in the protective zone. Quantities such as digital packet loss, bit error rate and channel delay are monitored to determine the quality of the channel. These limits are determined and

set during relay commissioning. Once set, any channel quality problems that fall outside the set levels will indicate an alarm.

The previous examples show how some protective relay communications channels can be monitored and how the channel performance can be compared to performance criteria established by the entity. This standard does not state what the performance criteria will be; it just requires that the entity establish nominal criteria so Protection System channel monitoring can be performed.

How is the performance criteria of Protection System communications equipment involved in the maintenance program?

An entity determines the acceptable performance criteria, depending on the technology implemented. If the communications channel performance of a Protection System varies from the pre-determined performance criteria for that system, then these results should be investigated and resolved.

How do I verify the A/D converters of microprocessor-based relays?

There are a variety of ways to do this. Two examples would be: using values gathered via data communications and automatically comparing these values with values from other sources, or using groupings of other measurements (such as vector summation of bus feeder currents) for comparison. Many other methods are possible.

15.6 Alarms (Table 2)

In addition to the tables of maintenance for the components of a Protection System, there is an additional table added for alarms. This additional table was added for clarity. This enabled the common alarm attributes to be consolidated into a single spot, and, thus, make it easier to read the Tables 1-1 through 1-5, Table 3, and Table 4. The alarms need to arrive at a site wherein a corrective action can be initiated. This could be a control room, operations center, etc. The alarming mechanism can be a standard alarming system or an auto-polling system; the only requirement is that the alarm be brought to the action-site within 24 hours. This effectively makes manned-stations equivalent to monitored stations. The alarm of a monitored point (for example a monitored trip path with a lamp) in a manned-station now makes that monitored point eligible for monitored status. Obviously, these same rules apply to a non-manned-station, which is that if the monitored point has an alarm that is auto-reported to the operations center (for example) within 24 hours, then it too is considered monitored.

15.6.1 Frequently Asked Questions:

Why are there activities defined for varying degrees of monitoring a Protection System component when that level of technology may not yet be available?

There may already be some equipment available that is capable of meeting the highest levels of monitoring criteria listed in the Tables. However, even if there is no equipment available today that can meet this level of monitoring the standard establishes the necessary requirements for when such equipment becomes available. By creating a roadmap for development, this provision makes the standard technology neutral. The Standard Drafting Team wants to avoid the need to revise the standard in a few years to accommodate technology advances that may be coming to the industry.

Does a fail-safe "form b" contact that is alarmed to a 24/7 operation center classify as an alarm path with monitoring?

If the fail-safe "form-b" contact that is alarmed to a 24/7 operation center causes the alarm to activate for failure of any portion of the alarming path from the alarm origin to the 24/7 operations center, then this can be classified as an alarm path with monitoring.

15.7 Distributed UFLS and Distributed UVLS Systems (Table 3)

Distributed UFLS and distributed UVLS systems have their maintenance activities documented in Table 3 due to their distributed nature allowing reduced maintenance activities and extended maximum maintenance intervals. Relays have the same maintenance activities and intervals as Table 1-1. Voltage and current-sensing devices have the same maintenance activity and interval as Table 1-3. DC systems need only have their voltage read at the relay every 12 years. Control circuits have the following maintenance activities every 12 years:

- Verify the trip path between the relay and lock-out and/or auxiliary tripping device(s).
- Verify operation of any lock-out and/or auxiliary tripping device(s) used in the trip circuit.
- No verification of trip path required between the lock-out (and/or auxiliary tripping device) and the non-BES interrupting device.
- No verification of trip path required between the relay and trip coil for circuits that have no lock-out and/or auxiliary tripping device(s).
- No verification of trip coil required.

No maintenance activity is required for associated communication systems for distributed UFLS and distributed UVLS schemes.

Non-BES interrupting devices that participate in a distributed UFLS or distributed UVLS scheme are excluded from the tripping requirement, and part of the control circuit test requirement; however, the part of the trip path control circuitry between the Load-Shed relay and lock-out or auxiliary tripping relay must be tested at least once every 12 years. In the case where there is no lock-out or auxiliary tripping relay used in a distributed UFLS or UVLS scheme which is not part of the BES, there is no control circuit test requirement. There are many circuit interrupting devices in the distribution system that will be operating for any given under-frequency event that requires tripping for that event. A failure in the tripping action of a single distributed system circuit breaker (or non-BES equipment interruption device) will be far less significant than, for example, any single transmission Protection System failure, such as a failure of a bus differential lock-out relay. While many failures of these distributed system circuit breakers (or non-BES equipment interruption device) could add up to be significant, it is also believed that many circuit breakers are operated often on just Fault clearing duty; and, therefore, these circuit breakers are operated at least as frequently as any requirements that appear in this standard.

There are times when a Protection System component will be used on a BES device, as well as a non-BES device, such as a battery bank that serves both a BES circuit breaker and a non-BES interrupting device used for UFLS. In such a case, the battery bank (or other Protection System component) will be subject to the Tables of the standard because it is used for the BES.

15.7.1 Frequently Asked Questions:

The standard reaches further into the distribution system than we would like for UFLS and UVLS

While UFLS and UVLS equipment are located on the distribution network, their job is to protect the Bulk Electric System. This is not beyond the scope of NERC's 215 authority.

FPA section 215(a) definitions section defines bulk power system as: "(A) facilities and control Systems necessary for operating an interconnected electric energy transmission network (or any portion thereof)." That definition, then, is limited by a later statement which adds the term bulk power system "…does not include facilities used in the local distribution of electric energy." Also, Section 215 also covers users, owners, and operators of bulk power Facilities.

UFLS and UVLS (when the UVLS is installed to prevent system voltage collapse or voltage instability for BES reliability) are not "used in the local distribution of electric energy," despite their location on local distribution networks. Further, if UFLS/UVLS Facilities were not covered by the reliability standards, then in order to protect the integrity of the BES during under-frequency or under-voltage events, that Load would have to be shed at the Transmission bus to ensure the Load-generation balance and voltage stability is maintained on the BES.

15.8 Automatic Reclosing (Table 4)

Please see the document referenced in Section F of PRC-005-3, "Considerations for Maintenance and Testing of Autoreclosing Schemes — November 2012", for a discussion of Automatic Reclosing as addressed in PRC-005-3.

15.8.1 Frequently-asked Questions

Automatic Reclosing is a control, not a protective function; why then is Automatic Reclosing maintenance included in the Protection System Maintenance Program (PSMP)?

Automatic Reclosing is a control function. The standard's title 'Protection System and Automatic Reclosing Maintenance' clearly distinguishes (separates) the Automatic Reclosing from the Protection System. Automatic Reclosing is included in the PSMP because it is a more pragmatic approach as compared to creating a parallel and essentially identical 'Control System Maintenance Program' for the two Automatic Reclosing component types.

Our maintenance practice consists of initiating the Automatic Reclosing relay and confirming the breaker closes properly and the close signal is released. This practice verifies the control circuitry associated with Automatic Reclosing. Do you agree?"

The described task partially verifies the control circuit maintenance activity. To meet the control circuit maintenance activity, responsible entities need to verify, *upon initiation*, that the reclosing relay does not issue a *premature closing command*. As noted on page 12 of the SAMS/SPCS report, the concern being addressed within the standard is premature autoreclosing that has the potential to cause generating unit or plant instability. Reclosing applications have many variations, responsible entities will need to verify the applicability of associated supervision/conditional logic and the reclosing relay operation; then verify the conditional logic or that the reclosing relay performs in a manner that does not result in a *premature closing command* being issued.

Some examples of conditions which can result in a premature closing command are: an improper supervision or conditional logic input which provides a false state and allows the reclosing relay to issue an improper close command based on incorrect conditions (i.e. voltage supervision, equipment status, sync window verification); timers utilized for closing actuation or reclosing arming/disarming circuitry which could allow the reclosing relay to issue an improper close command; a reclosing relay output contact failure which could result in a made-up-close condition / failure-to-release condition.

Why was a close-in three phase fault present for twice the normal clearing time chosen for the Automatic Reclosing exclusion? It exceeds TPL requirements and ignores the breaker closing time in a trip-close-trip sequence, thus making the exclusion harder to attain.

This condition represents a situation where a close signal is issued with no time delay or with less time delay than is intended, such as if a reclosing contact is welded closed. This failure mode can result in a minimum trip-close-trip sequence with the two faults cleared in primary protection operating time, and the open time between faults equal to the breaker closing cycle time. The sequence for this failure mode results in system impact equivalent to a high-speed autoreclosing sequence with no delay added in the autoreclosing logic. It represents a failure mode which must be avoided because it exceeds TPL requirements.

Do we have to test the various breaker closing circuit interlocks and controls such as anti-pump?

These components are not specifically addressed within Table 4, and need not be individually tested. They are indirectly verified by performing the Automatic Reclosing control circuitry verification as established in Table 4.

For Automatic Reclosing that is not part of an SPS, do we have to close the circuit breaker periodically?

No. For this application, you need only to verify that the Automatic Reclosing, upon initiation, does not issue a premature closing command. This activity is concerned only with assuring that a premature close does not occur, and cause generating plant instability.

For Automatic Reclosing that is part of an SPS, do we have to close the circuit breaker periodically?

Yes. In this application, successful closing is a necessary portion of the SPS, and must be verified.

15.9 Sudden Pressure Relaying (Table 5)

Please see the document referenced in Section F of PRC-005-4, "Sudden Pressure Relays and Other Devices that Respond to Non-Electrical Quantities – December 2013", for a discussion of Sudden Pressure Relaying as addressed in PRC-005-4.

15.9.1 Frequently Asked Questions:

How do I verify the pressure or flow sensing mechanism is operable?

Operate, or cause to operate the mechanism responding to the rapid-pressure rise. The standard does not specify how ***to*** perform the maintenance.

Why do I have to test the fault pressure relay every 6 years? Our experience is that these devices have no trouble operating as we have had our share of nuisance trips on through-faults?

~~a.~~ The frequency of the testing is set to align with previously set maintenance intervals in PRC-005 and align with a survey of respondents as detailed in the previously noted NERC SPCS paper responding to FERC Order 758.

Sudden Pressure Relaying control circuitry is now specifically mentioned in the maintenance tables, do we have to trip our circuit breaker specifically from the trip output of the sudden pressure relay?

No. Verification may be by breaker tripping, but may be verified in overlapping segments with the Protection System control circuitry.

Can we utilize Performance Based Maintenance for fault pressure relays?

Yes. Performance Based Maintenance is applicable to fault pressure relays.

15.10~~9~~ Examples of Evidence of Compliance

To comply with the requirements of this standard, an entity will have to document and save evidence. The evidence can be of many different forms. The Standard Drafting Team recognizes that there are concurrent evidence requirements of other NERC standards that could, at times, fulfill evidence requirements of this standard.

15.10~~9~~.1 Frequently Asked Questions:

What forms of evidence are acceptable?

Acceptable forms of evidence, as relevant for the requirement being documented include, but are not limited to:

- Process documents or plans
- Data (such as relay settings sheets, photos, SCADA, and test records)
- Database lists, records and/or screen shots that demonstrate compliance information
- Prints, diagrams and/or schematics
- Maintenance records
- Logs (operator, substation, and other types of log)
- Inspection forms
- Mail, memos, or email proving the required information was exchanged, coordinated, submitted or received
- Check-off forms (paper or electronic)
- Any record that demonstrates that the maintenance activity was known, accounted for, and/or performed.

If I replace a failed Protection System component with another component, what testing do I need to perform on the new component?

In order to reset the Table 1 maintenance interval for the replacement component, all relevant Table 1 activities for the component should be performed.

I have evidence to show compliance for PRC-016 ("Special Protection System Misoperation"). Can I also use it to show compliance for this Standard, ~~PRC-005-3~~PRC-005-4?

Maintaining evidence for operation of Special Protection Systems could concurrently be utilized as proof of the operation of the associated trip coil (provided one can be certain of the trip coil involved). Thus, the reporting requirements that one may have to do for the Misoperation of a Special Protection Scheme under PRC-016 could work for the activity tracking requirements under this ~~PRC-005-3~~PRC-005-4.

I maintain Disturbance records which show Protection System operations. Can I use these records to show compliance?

These records can be concurrently utilized as dc trip path verifications, to the degree that they demonstrate the proper function of that dc trip path.

I maintain test reports on some of my Protection System components. Can I use these test reports to show that I have verified a maintenance activity?

Yes.

References

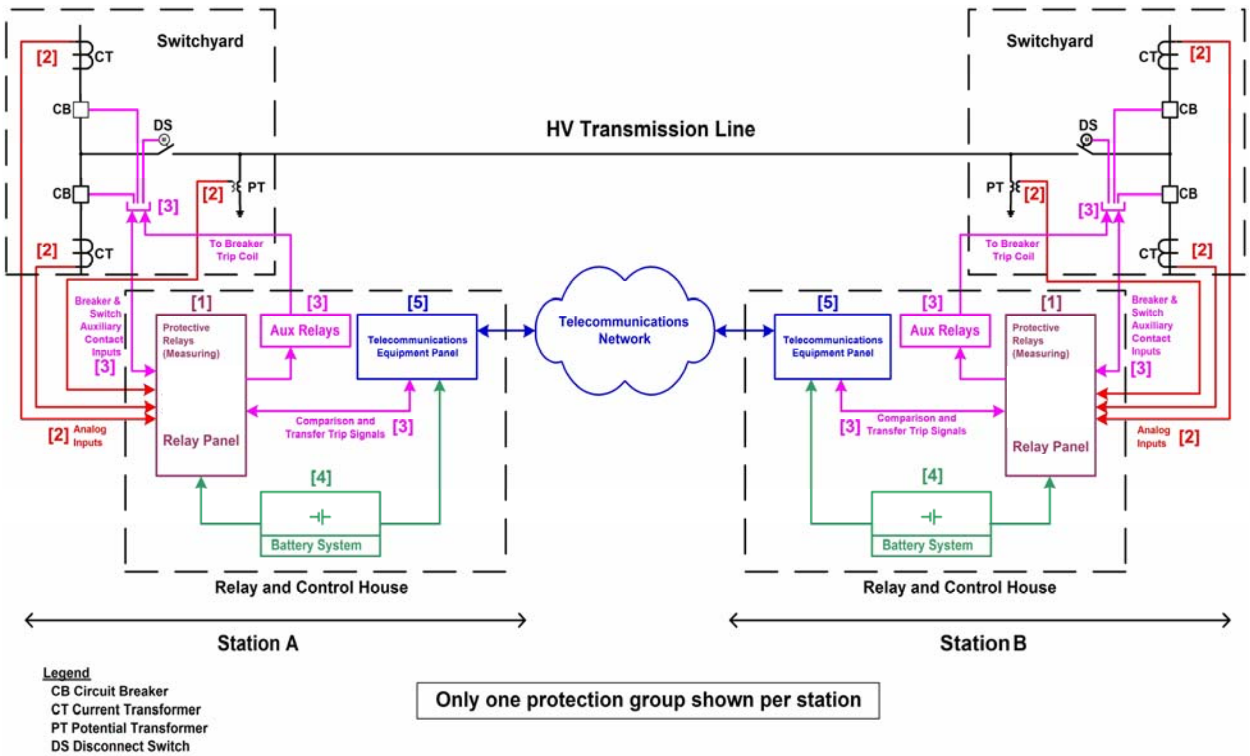
1. Protection System Maintenance: A Technical Reference. Prepared by the System Protection and Controls Task Force of the NERC Planning Committee. Dated September 13, 2007.
2. "Predicating The Optimum Routine test Interval For Protection Relays," by J. J. Kumm, M.S. Weber, D. Hou, and E. O. Schweitzer, III, IEEE Transactions on Power Delivery, Vol. 10, No. 2, April 1995.
3. "Transmission Relay System Performance Comparison For 2000, 2001, 2002, 2003, 2004 and 2005," Working Group I17 of Power System Relaying Committee of IEEE Power Engineering Society, May 2006.
4. "A Survey of Relaying Test Practices," Special Report by WG I11 of Power System Relaying Committee of IEEE Power Engineering Society, September 16, 1999.
5. "Transmission Protective Relay System Performance Measuring Methodology," Working Group I3 of Power System Relaying Committee of IEEE Power Engineering Society, January 2002.
6. "Processes, Issues, Trends and Quality Control of Relay Settings," Working Group C3 of Power System Relaying Committee of IEEE Power Engineering Society, December 2006.
7. "Proposed Statistical Performance Measures for Microprocessor-Based Transmission-Line Protective Relays, Part I - Explanation of the Statistics, and Part II - Collection and Uses of Data," Working Group D5 of Power System Relaying Committee of IEEE Power Engineering Society, May 1995; Papers 96WM 016-6 PWRD and 96WM 127-1 PWRD, 1996 IEEE Power Engineering Society Winter Meeting.
8. "Analysis And Guidelines For Testing Numerical Protection Schemes," Final Report of CIGRE WG 34.10, August 2000.
9. "Use of Preventative Maintenance and System Performance Data to Optimize Scheduled Maintenance Intervals," H. Anderson, R. Loughlin, and J. Zipp, Georgia Tech Protective Relay Conference, May 1996.
10. "Battery Performance Monitoring by Internal Ohmic Measurements" EPRI Application Guidelines for Stationary Batteries TR- 108826 Final Report, December 1997.
11. "IEEE Recommended Practice for Maintenance, Testing, and Replacement of Valve-Regulated Lead-Acid (VRLA) Batteries for Stationary Applications," IEEE Power Engineering Society Std 1188 – 2005.
12. "IEEE Recommended Practice for Maintenance, Testing, and Replacement of Vented Lead-Acid Batteries for Stationary Applications," IEEE Power & Engineering Society Std 45-2010.
13. "IEEE Recommended Practice for Installation design and Installation of Vented Lead-Acid Batteries for Stationary Applications," IEEE Std 484 – 2002.
14. "Stationary Battery Monitoring by Internal Ohmic Measurements," EPRI Technical Report, 1002925 Final Report, December 2002.
15. "Stationary Battery Guide: Design Application, and Maintenance" EPRI Revision 2 of TR-100248, 1006757, August 2002.

PSMT SDT References

16. “Essentials of Statistics for Business and Economics” Anderson, Sweeney, Williams, 2003
17. “Introduction to Statistics and Data Analysis” - Second Edition, Peck, Olson, Devore, 2005
18. “Statistical Analysis for Business Decisions” Peters, Summers, 1968
19. “Considerations for Maintenance and Testing of Autoreclosing Schemes,” NERC System Analysis and Modeling Subcommittee and NERC System Protection and Control Subcommittee, November 2012

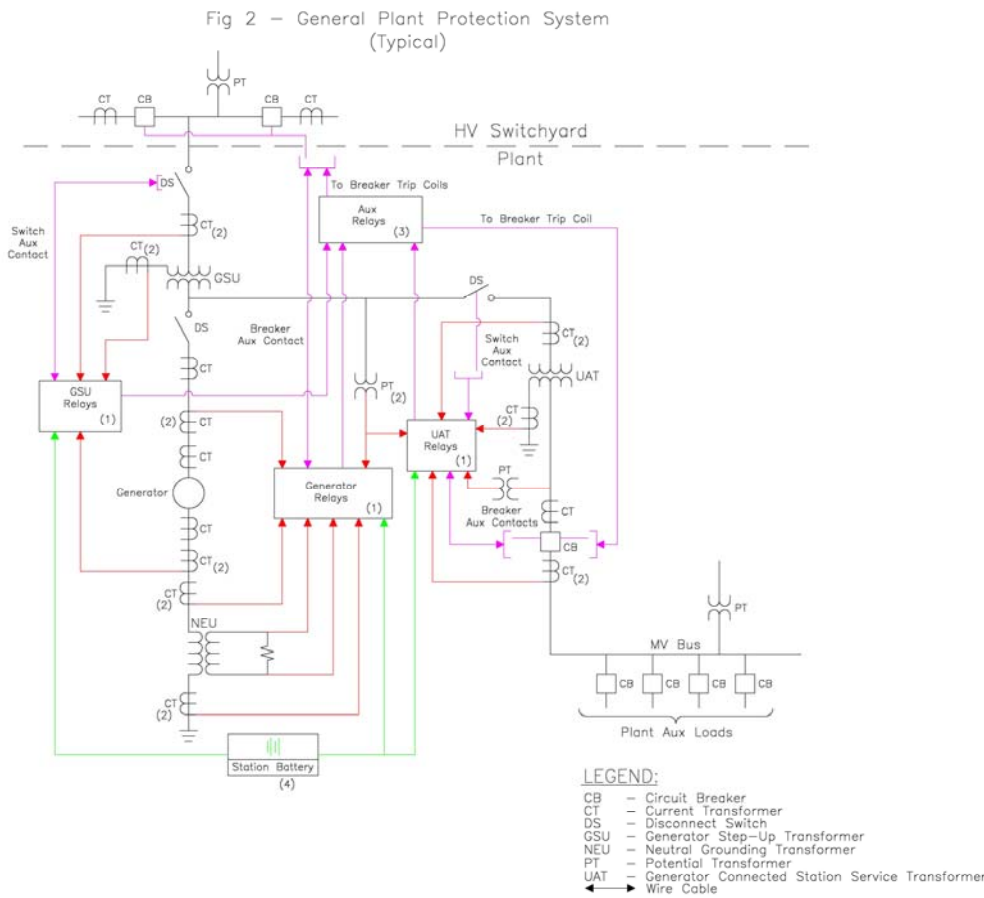
Figures

Figure 1: Typical Transmission System



For information on components, see ***[Figure 1 & 2 Legend – components of Protection Systems]***

Figure 2: Typical Generation System



Note: Figure 2 may show elements that are not included within PRC-005-2, and also may not be all-inclusive; see the Applicability section of the standard for specifics.

For information on components, see ***Figure 1 & 2 Legend – components of Protection Systems***

Figure 1 & 2 Legend – Components of Protection Systems

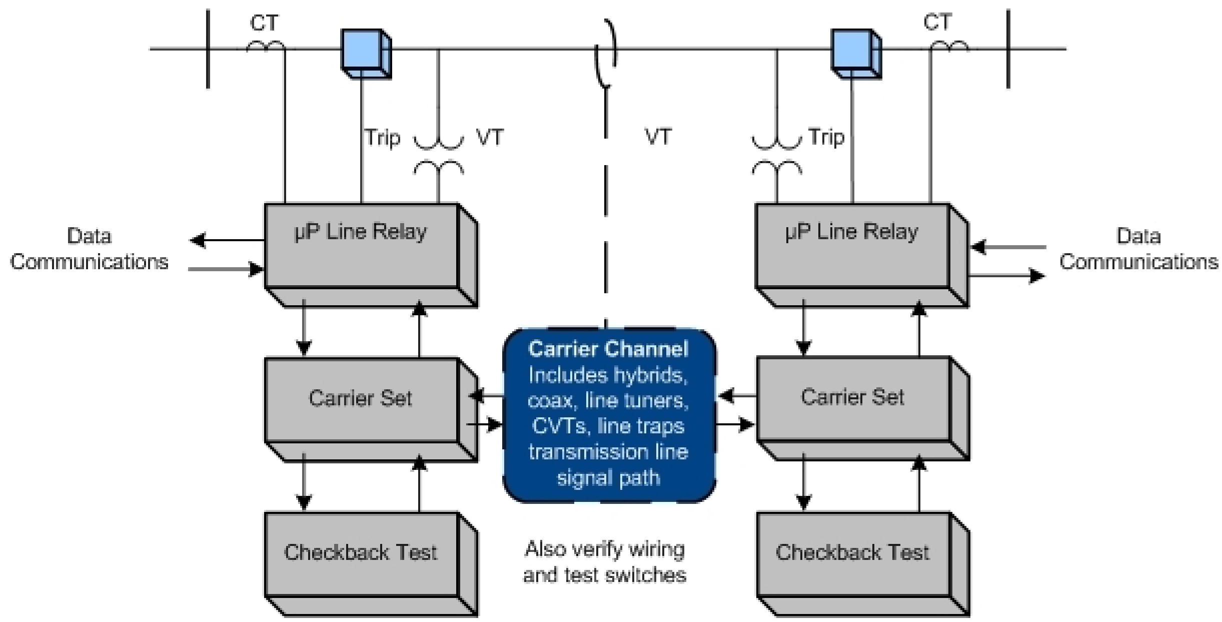
Number in Figure	Component of Protection System	Includes	Excludes
1	Protective relays which respond to electrical quantities	All protective relays that use current and/or voltage inputs from current & voltage sensors and that trip the 86, 94 or trip coil.	Devices that use non-electrical methods of operation including thermal, pressure, gas accumulation, and vibration. Any ancillary equipment not specified in the definition of Protection Systems. Control and/or monitoring equipment that is not a part of the automatic tripping action of the Protection System
2	Voltage and current sensing devices providing inputs to protective relays	The signals from the voltage & current sensing devices to the protective relay input.	Voltage & current sensing devices that are not a part of the Protection System, including sync-check systems, metering systems and data acquisition systems.
3	Control circuitry associated with protective functions	All control wiring (or other medium for conveying trip signals) associated with the tripping action of 86 devices, 94 devices or trip coils (from all parallel trip paths). This would include fiber-optic systems that carry a trip signal as well as hard-wired systems that carry trip current.	Closing circuits, SCADA circuits, other devices in control scheme not passing trip current
4	Station dc supply	Batteries and battery chargers and any control power system which has the function of supplying power to the protective relays, associated trip circuits and trip coils.	Any power supplies that are not used to power protective relays or their associated trip circuits and trip coils.
5	Communications systems necessary for correct operation of protective functions	Tele-protection equipment used to convey specific information, in the form of analog or digital signals, necessary for the correct operation of protective functions.	Any communications equipment that is not used to convey information necessary for the correct operation of protective functions.

Additional information can be found in References

Appendix A

The following illustrates the concept of overlapping verifications and tests as summarized in Section 10 of the paper. As an example, Figure A-1 shows protection for a critical transmission line by carrier blocking directional comparison pilot relaying. The goal is to verify the ability of the entire two-terminal pilot protection scheme to protect for line Faults, and to avoid over-tripping for Faults external to the transmission line zone of protection bounded by the current transformer locations.

Figure A-1



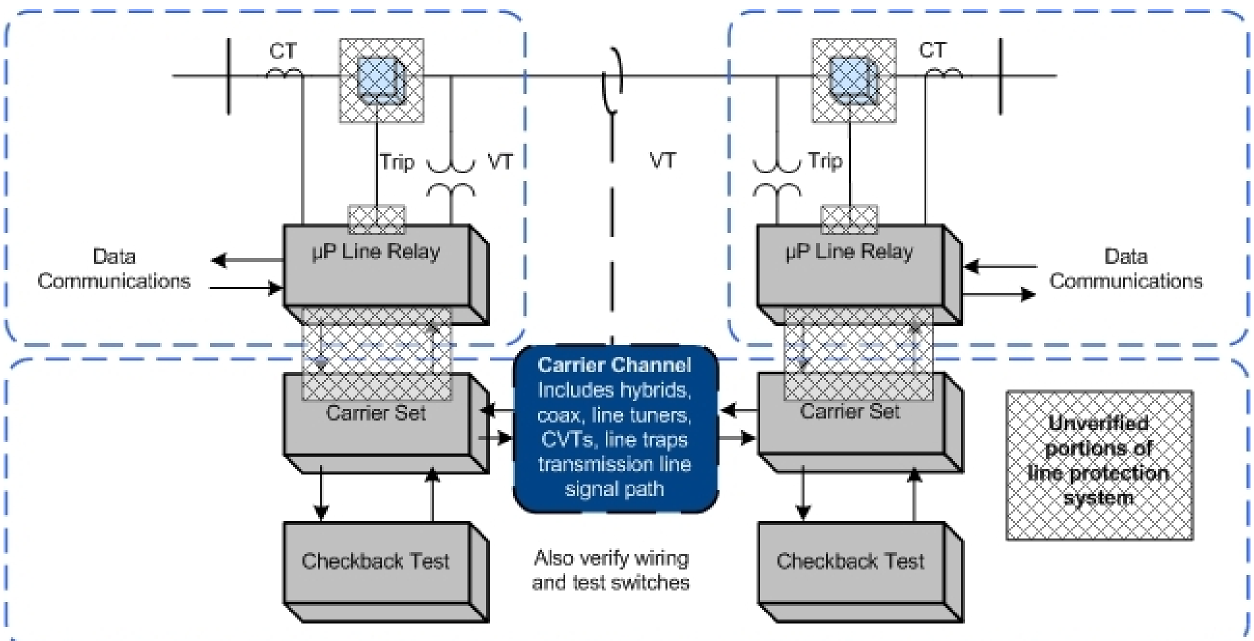
In this example (Figure A1), verification takes advantage of the self-monitoring features of microprocessor multifunction line relays at each end of the line. For each of the line relays themselves, the example assumes that the user has the following arrangements in place:

1. The relay has a data communications port that can be accessed from remote locations.
2. The relay has internal self-monitoring programs and functions that report failures of internal electronics, via communications messages or alarm contacts to SCADA.
3. The relays report loss of dc power, and the relays themselves or external monitors report the state of the dc battery supply.
4. The CT and PT inputs to the relays are used for continuous calculation of metered values of volts, amperes, plus Watts and VARs on the line. These metered values are reported by data communications. For maintenance, the user elects to compare these readings to those of other relays, meters, or DFRs. The other readings may be from redundant relaying or measurement systems or they may be derived from values in other protection zones. Comparison with other such readings to within required relaying accuracy verifies voltage & current sensing devices, wiring, and analog signal input processing of the relays. One effective way to do this is to utilize the relay metered values directly in SCADA, where they can be compared with other references or state estimator values.

5. Breaker status indication from auxiliary contacts is verified in the same way as in (2). Status indications must be consistent with the flow or absence of current.
6. Continuity of the breaker trip circuit from dc bus through the trip coil is monitored by the relay and reported via communications.
7. Correct operation of the on-off carrier channel is also critical to security of the Protection System, so each carrier set has a connected or integrated automatic checkback test unit. The automatic checkback test runs several times a day. Newer carrier sets with integrated checkback testing check for received signal level and report abnormal channel attenuation or noise, even if the problem is not severe enough to completely disable the channel.

These monitoring activities plus the check-back test comprise automatic verification of all the Protection System elements that experience tells us are the most prone to fail. But, does this comprise a complete verification?

Figure A-2



The dotted boxes of Figure A-2 show the sections of verification defined by the monitoring and verification practices just listed. These sections are not completely overlapping, and the shaded regions show elements that are not verified:

1. The continuity of trip coils is verified, but no means is provided for validating the ability of the circuit breaker to trip if the trip coil should be energized.
2. Within each line relay, all the microprocessors that participate in the trip decision have been verified by internal monitoring. However, the trip circuit is actually energized by the

contacts of a small telephone-type "ice cube" relay within the line protective relay. The microprocessor energizes the coil of this ice cube relay through its output data port and a transistor driver circuit. There is no monitoring of the output port, driver circuit, ice cube relay, or contacts of that relay. These components are critical for tripping the circuit breaker for a Fault.

3. The check-back test of the carrier channel does not verify the connections between the relaying microprocessor internal decision programs and the carrier transmitter keying circuit or the carrier receiver output state. These connections include microprocessor I/O ports, electronic driver circuits, wiring, and sometimes telephone-type auxiliary relays.
4. The correct states of breaker and disconnect switch auxiliary contacts are monitored, but this does not confirm that the state change indication is correct when the breaker or switch opens.

A practical solution for (1) and (2) is to observe actual breaker tripping, with a specified maximum time interval between trip tests. Clearing of naturally-occurring Faults are demonstrations of operation that reset the time interval clock for testing of each breaker tripped in this way. If Faults do not occur, manual tripping of the breaker through the relay trip output via data communications to the relay microprocessor meets the requirement for periodic testing.

~~PRC-005-3~~PRC-005-4 does not address breaker maintenance, and its Protection System test requirements can be met by energizing the trip circuit in a test mode (breaker disconnected) through the relay microprocessor. This can be done via a front-panel button command to the relay logic, or application of a simulated Fault with a relay test set. However, utilities have found that breakers often show problems during Protection System tests. It is recommended that Protection System verification include periodic testing of the actual tripping of connected circuit breakers.

Testing of the relay-carrier set interface in (3) requires that each relay key its transmitter, and that the other relay demonstrate reception of that blocking carrier. This can be observed from relay or DFR records during naturally occurring Faults, or by a manual test. If the checkback test sequence were incorporated in the relay logic, the carrier sets and carrier channel are then included in the overlapping segments monitored by the two relays, and the monitoring gap is completely eliminated.

Appendix B

Protection System Maintenance Standard Drafting Team

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Standards Announcement Reminder

Project 2007-17.3 Protection System Maintenance and Testing: Sudden Pressure Relays
PRC-005-X

Ballot and Non-Binding Poll Now Open through June 2, 2014

Now Available

A ballot for **PRC-005-X – Protection System, Automatic Reclosing, and Sudden Pressure Relaying Maintenance** and non-binding poll of the associated Violation Risk Factors (VRFs) and Violation Severity Levels (VSLs) are now open through **8 p.m. Eastern on Monday, June 2, 2014.**

If you have questions please contact Jordan Mallory via email or by telephone at (404) 446-9733.

Background information for this project can be found on the project page.

Instructions for Balloting

Members of the ballot pools associated with this project may log in and submit their vote for the standard and non-binding poll of the associated VRFs and VSLs by clicking here.

Next Steps

The ballot results will be announced and posted on the project page. The drafting team will consider all comments received during the formal comment period and, if needed, make revisions to the standard. If the comments do not show the need for significant revisions, the standard will proceed to a final ballot.

For more information on the **Standards Development Process**, please refer to the Standard Processes Manual.

For more information or assistance, please contact Wendy Muller,
Standards Development Administrator, or at 404-446-2560.

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Standards Announcement

Project 2007-17.3 Protection System Maintenance and Testing: Sudden Pressure Relays PRC-005-X

Formal Comment Period Now Open through June 2, 2014
Ballot Pools Forming Now through May 16, 2014

Now Available

A 45-day formal comment period for **PRC-005-X – Protection System, Automatic Reclosing, and Sudden Pressure Relaying Maintenance** is open through **8 p.m. Eastern on Monday, June 2, 2014.**

If you have questions please contact Jordan Mallory via email or by telephone at (404) 446-9733.

Background information for this project can be found on the project page.

Instructions for Commenting

Please use the electronic form to submit comments on the revised definition. If you experience any difficulties in using the electronic form, please contact Wendy Muller. An off-line, unofficial copy of the comment form is posted on the project page.

Instructions for Joining Ballot Pool

Ballots pools are being formed for Project 2007-17.3 – Protection System Maintenance and Testing: Sudden Pressure Relays and the associated non-binding poll on this project. Registered Ballot Body members must join the ballot pools to be eligible to vote in the balloting and submittal of an opinion for the non-binding poll of the associated Violation Risk Factors (VRFs) and Violation Severity Levels (VSLs). Registered Ballot Body members may join the ballot pools at the following page: Join Ballot Pool

During the pre-ballot window, members of the ballot pool may communicate with one another by using their “ballot pool list server.” (Once the balloting begins, ballot pool members are prohibited from using the ballot pool list servers.) The list servers for this project are:

Initial Ballot: bp-2007-17.3_PRC-005-X_in@nerc.com
Non-Binding poll: bp-2007-17_PRC-005-X_NB_in@nerc.com

Next Steps

An initial ballot for the standard and non-binding poll of the associated VRFs and VSLs will be conducted **May 23 – June 2, 2014.**

For more information on the **Standards Development Process**, please refer to the Standard Processes Manual.

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NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

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Project 2007-17.3 Protection System Maintenance and Testing: Sudden Pressure Relays
PRC-005-X

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Initial Ballot: bp-2007-17.3_PRC-005-X_in@nerc.com
Non-Binding poll: bp-2007-17_PRC-005-X_NB_in@nerc.com

Next Steps

An initial ballot for the standard and non-binding poll of the associated VRFs and VSLs will be conducted **May 23 – June 2, 2014.**

For more information on the **Standards Development Process**, please refer to the Standard Processes Manual.

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Standards Announcement

Project 2007-17.3 Protection Systems Maintenance and Testing – Sudden Pressure Relays
PRC-005-X

Ballot and Non-Binding Poll Results

Now Available

A ballot for **PRC-005-X – Protection System, Automatic Reclosing, and Sudden Pressure Relaying Maintenance** and a non-binding poll of the associated Violation Risk Factors and Violation Severity Levels concluded at **8 p.m. Eastern on Tuesday, June 3, 2013**.

This standard achieved a quorum but did not receive sufficient affirmative votes for approval. Voting statistics are listed below, and the Ballot Results page provides a link to the detailed results for the ballot.

Ballot	Non-Binding Poll
Quorum /Approval	Quorum/Supportive Opinions
85.42% / 47.89%	85.67% / 47.77%

Background information for this project can be found on the project page.

Next Steps
The drafting team will consider all comments received during the formal comment period and, if needed, make revisions to the standard. If the comments show the need for significant revisions, the standard will proceed to an additional comment and ballot period. If the comments do not show the need for significant revisions, the standard will proceed to a final ballot.

For more information on the **Standards Development Process**, please refer to the Standard Processes Manual.

For more information or assistance, please contact Wendy Muller,
Standards Development Administrator, or at 404-446-2560.

Ballot Results	
Ballot Name:	Project 2007-17.3 PSMT - Sudden Pressure Relays PRC-005-X
Ballot Period:	5/23/2014 - 6/3/2014
Ballot Type:	Initial
Total # Votes:	328
Total Ballot Pool:	384
Quorum:	**85.42 % The Quorum has been reached**
Weighted Segment Vote:	47.89 %
Ballot Results:	**The ballot has closed**

Summary of Ballot Results

Segment	Ballot Pool	Segment Weight	Affirmative # Votes	Affirmative Fraction	Negative # Votes	Negative Fraction	Negative Vote without a Comment	Abstain	No Vote
1 - Segment 1	105	1	42	0.512	40	0.488	0	8	15
2 - Segment 2	9	0.5	1	0.1	4	0.4	0	4	0
3 - Segment 3	82	1	35	0.507	34	0.493	0	5	8
4 - Segment 4	29	1	6	0.231	20	0.769	0	2	1
5 - Segment 5	88	1	27	0.466	31	0.534	0	8	22
6 - Segment 6	54	1	24	0.545	20	0.455	0	3	7
7 - Segment 7	2	0.2	1	0.1	1	0.1	0	0	0
8 - Segment 8	4	0.2	1	0.1	1	0.1	0	1	1
9 - Segment 9	2	0.1	1	0.1	0	0	0	0	1

10 - Segment 10	9	0.6	5	0.5	1	0.1	0	2	1
Totals	**384**	**6.6**	**143**	**3.161**	**152**	**3.439**	**0**	**33**	**56**

Individual Ballot Pool Results

Segment	Organization	Member	Ballot	NERC Notes
1	Ameren Services	Eric Scott	Negative	SUPPORTS THIRD PARTY COMMENTS - (Ameren)
1	American Electric Power	Paul B Johnson	Affirmative	
1	American Transmission Company, LLC	Andrew Z Pusztai	Abstain	
1	Arizona Public Service Co.	Robert Smith		
1	Associated Electric Cooperative, Inc.	John Bussman	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
1	ATCO Electric	Glen Sutton	Negative	COMMENT RECEIVED
1	Austin Energy	James Armke	Negative	SUPPORTS THIRD PARTY COMMENTS - (Andrew Gallo)
1	Avista Utilities	Heather Rosentrater	Negative	COMMENT RECEIVED
1	Balancing Authority of Northern California	Kevin Smith	Negative	COMMENT RECEIVED
1	Baltimore Gas & Electric Company	Christopher J Scanlon	Affirmative	
1	BC Hydro and Power Authority	Patricia Robertson	Abstain	
1	Black Hills Corp	Wes Wingen	Abstain	
1	Bonneville Power Administration	Donald S. Watkins	Affirmative	
1	Bryan Texas Utilities	John C Fontenot	Affirmative	
1	CenterPoint Energy Houston Electric, LLC	John Brockhan	Affirmative	
1	Central Electric Power Cooperative	Michael B Bax	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
1	Central Iowa Power Cooperative	Kevin J Lyons	Negative	SUPPORTS THIRD PARTY COMMENTS - (CIPCO supports the comments submitted by NRECA and ACES.)
1	City and County of San Francisco	Lenise Kimes	Abstain	
1	City of Tacoma, Department of Public Utilities, Light Division, dba Tacoma Power	Chang G Choi	Negative	COMMENT RECEIVED
1	City of Tallahassee	Daniel S Langston	Negative	COMMENT RECEIVED
1	Clark Public Utilities	Jack Stamper	Affirmative	
1	Colorado Springs Utilities	Shawna Speer	Negative	SUPPORTS THIRD PARTY COMMENTS - (Kaleb Brimhall - Colorado Springs Utilities)
1	Consolidated Edison Co. of New York	Christopher L de Graffenried	Affirmative	
1	CPS Energy	Glenn Pressler	Affirmative	
1	Dairyland Power Coop.	Robert W. Roddy	Affirmative	
1	Dayton Power & Light Co.	Hertzel Shamash		
1	Dominion Virginia Power	Larry Nash	Affirmative	
1	Duke Energy Carolina	Doug E Hils	Affirmative	
1	Duquesne Light Co.	Hugh R Conley		
				SUPPORTS

1	East Kentucky Power Coop.	Amber Anderson	Negative	THIRD PARTY COMMENTS - (ACES)
1	Empire District Electric Co.	Ralph F Meyer		
1	Encari	Steven E Hamburg		
1	Entergy Transmission	Oliver A Burke	Affirmative	
1	FirstEnergy Corp.	William J Smith	Affirmative	
1	Florida Keys Electric Cooperative Assoc.	Dennis Minton	Affirmative	
1	Florida Power & Light Co.	Mike O'Neil	Affirmative	
1	Gainesville Regional Utilities	Richard Bachmeier	Negative	SUPPORTS THIRD PARTY COMMENTS - (FLorida Municipal Power Agency)
1	Georgia Transmission Corporation	Jason Snodgrass	Negative	COMMENT RECEIVED
1	Great River Energy	Gordon Pietsch	Affirmative	
1	Hoosier Energy Rural Electric Cooperative, Inc.	Bob Solomon	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
1	Hydro One Networks, Inc.	Muhammed Ali	Affirmative	
1	Hydro-Quebec TransEnergie	Martin Boisvert	Negative	COMMENT RECEIVED
1	Idaho Power Company	Molly Devine	Affirmative	
1	International Transmission Company Holdings Corp	Michael Moltane		
1	JDRJC Associates	Jim D Cyrulewski	Affirmative	
1	JEA	Ted E Hobson	Negative	COMMENT RECEIVED
1	Kansas City Power & Light Co.	Daniel Gibson	Affirmative	
1	Keys Energy Services	Stanley T Rzad		
1	Lakeland Electric	Larry E Watt	Negative	SUPPORTS THIRD PARTY COMMENTS - (Florida Municipal Power Agency)
1	Lee County Electric Cooperative	John Chin		
1	Lincoln Electric System	Doug Bantam	Affirmative	
1	Long Island Power Authority	Robert Ganley		
1	Los Angeles Department of Water & Power	faranak sarbaz	Negative	COMMENT RECEIVED
1	Lower Colorado River Authority	Martyn Turner	Negative	SUPPORTS THIRD PARTY COMMENTS - (Lower Colorado River Authority)
1	M & A Electric Power Cooperative	William Price	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
1	Manitoba Hydro	Jo-Anne M Ross	Affirmative	
1	MidAmerican Energy Co.	Terry Harbour	Affirmative	
1	Minnkota Power Coop. Inc.	Daniel L Inman	Negative	SUPPORTS THIRD PARTY COMMENTS - (MRO's NERC Standards Review Forum (NSRF))
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
1	National Grid USA	Michael Jones	Affirmative	
1	NB Power Corporation	Alan MacNaughton		
1	Nebraska Public Power District	Jamison Cawley	Negative	COMMENT RECEIVED
1	New York Power Authority	Bruce Metruck	Affirmative	

1	Northeast Missouri Electric Power Cooperative	Kevin White	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
1	Northeast Utilities	William Temple	Affirmative	
1	Northern Indiana Public Service Co.	Julaine Dyke	Affirmative	
1	NorthWestern Energy	John Canavan	Affirmative	
1	Ohio Valley Electric Corp.	Scott R Cunningham	Affirmative	
1	Oklahoma Gas and Electric Co.	Terri Pyle	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP Standards Review Group Comments)
1	Omaha Public Power District	Doug Peterchuck	Negative	SUPPORTS THIRD PARTY COMMENTS - (MRO NSRF)
1	Oncor Electric Delivery	Jen Fiegel	Affirmative	
1	Otter Tail Power Company	Daryl Hanson	Negative	SUPPORTS THIRD PARTY COMMENTS - (we support the comments of the MRO NSRF)
1	Pacific Gas and Electric Company	Bangalore Vijayraghavan	Affirmative	
1	Platte River Power Authority	John C. Collins	Affirmative	
1	Portland General Electric Co.	John T Walker	Negative	COMMENT RECEIVED
1	Potomac Electric Power Co.	David Thorne	Affirmative	
1	PPL Electric Utilities Corp.	Brenda L Truhe	Affirmative	
1	Public Service Company of New Mexico	Laurie Williams		
1	Public Service Electric and Gas Co.	Kenneth D. Brown	Negative	SUPPORTS THIRD PARTY COMMENTS - (Support comments to be filed by Public Service Enterprise Group ("PSEG").)
1	Puget Sound Energy, Inc.	Denise M Lietz	Abstain	
1	Rochester Gas and Electric Corp.	John C. Allen	Abstain	
1	Sacramento Municipal Utility District	Tim Kelley	Negative	COMMENT RECEIVED
1	Salt River Project	Robert Kondziolka		
1	SaskPower	Wayne Guttormson		
1	Seattle City Light	Pawel Krupa	Negative	SUPPORTS THIRD PARTY COMMENTS - (Seattle City Light's Paul Hasse's comment)
1	Seminole Electric Cooperative, Inc.	Glenn Spurlock	Negative	SUPPORTS THIRD PARTY COMMENTS - (Endorses NRECA comments)
1	Snohomish County PUD No. 1	Long T Duong	Negative	SUPPORTS THIRD PARTY COMMENTS - (Sacramento Municipal Utility District ("SMUD"))
1	South Carolina Electric & Gas Co.	Tom Hanzlik	Affirmative	
1	South Carolina Public Service Authority	Shawn T Abrams	Abstain	
1	Southern California Edison Company	Steven Mavis	Affirmative	
1	Southern Company Services, Inc.	Robert A. Schaffeld	Negative	SUPPORTS THIRD PARTY COMMENTS -

				(Southern Company)
1	Southern Illinois Power Coop.	William Hutchison	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
1	Southwest Transmission Cooperative, Inc.	John Shaver	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
1	Sunflower Electric Power Corporation	Noman Lee Williams	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
1	Tampa Electric Co.	Beth Young		
1	Tennessee Valley Authority	Howell D Scott	Affirmative	
1	Tri-State Generation & Transmission Association, Inc.	Tracy Sliman	Affirmative	
1	Tucson Electric Power Co.	John Tolo		
1	U.S. Bureau of Reclamation	Richard T Jackson	Negative	COMMENT RECEIVED
1	United Illuminating Co.	Jonathan Appelbaum	Negative	SUPPORTS THIRD PARTY COMMENTS - (NPCC)
1	Vermont Electric Power Company, Inc.	Kim Moulton	Affirmative	
1	Westar Energy	Allen Klassen	Affirmative	
1	Western Area Power Administration	Lloyd A Linke	Affirmative	
1	Wolverine Power Supply Coop., Inc.	Michelle Clements	Abstain	
1	Xcel Energy, Inc.	Gregory L Pieper	Affirmative	
2	BC Hydro	Venkataramakrishnan Vinnakota	Abstain	
2	California ISO	Rich Vine	Negative	SUPPORTS THIRD PARTY COMMENTS - (ISO/RTO Standards Review Committee)
2	Electric Reliability Council of Texas, Inc.	Cheryl Moseley	Negative	SUPPORTS THIRD PARTY COMMENTS - (IRC SRC)
2	Independent Electricity System Operator	Leonard Kula	Negative	COMMENT RECEIVED
2	ISO New England, Inc.	Matthew F Goldberg	Abstain	
2	MISO	Marie Knox	Abstain	
2	New York Independent System Operator	Gregory Campoli	Abstain	
2	PJM Interconnection, L.L.C.	stephanie monzon	Negative	SUPPORTS THIRD PARTY COMMENTS - (SRC)
2	Southwest Power Pool, Inc.	Charles H. Yeung	Affirmative	
3	AEP	Michael E Deloach	Affirmative	
3	Alabama Power Company	Robert S Moore	Negative	SUPPORTS THIRD PARTY COMMENTS - (Southern Company)
3	Ameren Corp.	David J Jendras	Negative	COMMENT RECEIVED
3	APS	Sarah Kist	Affirmative	
3	Associated Electric Cooperative, Inc.	Todd Bennett	Negative	SUPPORTS THIRD PARTY COMMENTS - (Associated Electric Cooperative Inc)
3	Atlantic City Electric Company	NICOLE BUCKMAN	Affirmative	
3	Avista Corp.	Scott J Kinney	Negative	SUPPORTS THIRD PARTY COMMENTS - (Heather Rosentrater)

3	BC Hydro and Power Authority	Pat G. Harrington	Abstain	
3	Bonneville Power Administration	Rebecca Berdahl	Affirmative	
3	Central Electric Power Cooperative	Adam M Weber	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
3	City of Anaheim Public Utilities Department	Dennis M Schmidt		
3	City of Austin dba Austin Energy	Andrew Gallo	Negative	COMMENT RECEIVED
3	City of Clewiston	Lynne Mila	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA)
3	City of Farmington	Linda R Jacobson	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA)
3	City of Green Cove Springs	Mark Schultz	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA)
3	City of Redding	Bill Hughes	Negative	SUPPORTS THIRD PARTY COMMENTS - (SMUD & FMPA)
3	City of Tallahassee	Bill R Fowler	Negative	COMMENT RECEIVED
3	Colorado Springs Utilities	Jean Mueller	Affirmative	
3	ComEd	John Bee	Affirmative	
3	Consolidated Edison Co. of New York	Peter T Yost	Affirmative	
3	Consumers Energy Company	Gerald G Farringer		
3	Cowlitz County PUD	Russell A Noble	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA)
3	CPS Energy	Jose Escamilla	Affirmative	
3	Delmarva Power & Light Co.	Michael R. Mayer	Affirmative	
3	Dominion Resources, Inc.	Connie B Lowe	Affirmative	
3	DTE Electric	Kent Kujala	Abstain	
3	East Kentucky Power Coop.	Patrick Woods	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
3	Empire District Electric Co.	Kalem Long		
3	FirstEnergy Corp.	Cindy E Stewart	Affirmative	
3	Florida Keys Electric Cooperative	Tom B Anthony	Affirmative	
3	Florida Municipal Power Agency	Joe McKinney	Negative	COMMENT RECEIVED
3	Florida Power Corporation	Lee Schuster	Affirmative	
3	Georgia System Operations Corporation	Scott McGough	Negative	SUPPORTS THIRD PARTY COMMENTS - (Georgia Transmission Corporation)
3	Great River Energy	Brian Glover	Affirmative	
3	Hydro One Networks, Inc.	Ayesha Sabouba	Affirmative	
3	JEA	Garry Baker	Negative	SUPPORTS THIRD PARTY COMMENTS - (JEA)
3	Kansas City Power & Light Co.	Joshua D Bach	Affirmative	
3	Kissimmee Utility Authority	Gregory D Woessner		
3	Lakeland Electric	Mace D Hunter	Negative	SUPPORTS THIRD PARTY COMMENTS - (Florida Municipal Power Agency)
3	Lee County Electric Cooperative	David A Hadzima		
3	Lincoln Electric System	Jason Fortik	Affirmative	
3	Los Angeles Department of Water & Power	Mike Anctil	Negative	COMMENT RECEIVED

3	Louisville Gas and Electric Co.	Charles A. Freibert	Affirmative	
3	Manitoba Hydro	Greg C. Parent	Affirmative	
3	MidAmerican Energy Co.	Thomas C. Mielnik	Affirmative	
3	Modesto Irrigation District	Jack W Savage	Negative	SUPPORTS THIRD PARTY COMMENTS - (Frank Gaffney (FMPA))
3	Muscatine Power & Water	John S Bos	Affirmative	
3	National Grid USA	Brian E Shanahan	Affirmative	
3	Nebraska Public Power District	Tony Eddleman	Negative	SUPPORTS THIRD PARTY COMMENTS - (Nebraska Public Power District comments and Southwest Power Pool comments.)
3	New York Power Authority	David R Rivera	Affirmative	
3	Northern Indiana Public Service Co.	Ramon J Barany	Affirmative	
3	NW Electric Power Cooperative, Inc.	David McDowell	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
3	Ocala Utility Services	Randy Hahn	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA)
3	Oklahoma Gas and Electric Co.	Donald Hargrove	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP Comments)
3	Omaha Public Power District	Blaine R. Dinwiddie	Negative	SUPPORTS THIRD PARTY COMMENTS - (MRO NSRF)
3	Orlando Utilities Commission	Ballard K Mutters	Negative	SUPPORTS THIRD PARTY COMMENTS - (I support the comments of FMPA (Florida Municipal Power Pool, Frank Gaffney))
3	Owensboro Municipal Utilities	Thomas T Lyons	Abstain	
3	Pacific Gas and Electric Company	John H Hagen	Affirmative	
3	Platte River Power Authority	Terry L Baker	Affirmative	
3	PNM Resources	Michael Mertz		
3	Portland General Electric Co.	Thomas G Ward	Negative	SUPPORTS THIRD PARTY COMMENTS - (PGE's comments)
3	Potomac Electric Power Co.	Mark Yerger	Affirmative	
3	Public Service Electric and Gas Co.	Jeffrey Mueller	Negative	SUPPORTS THIRD PARTY COMMENTS - (Support comments to be filed by Public Service Enterprise Group ("PSEG").)
3	Puget Sound Energy, Inc.	Mariah R Kennedy	Abstain	
3	Rutherford EMC	Thomas Haire	Negative	SUPPORTS THIRD PARTY COMMENTS - (NRECA)
3	Sacramento Municipal Utility District	James Leigh-Kendall	Negative	COMMENT

				RECEIVED
3	Salt River Project	John T. Underhill	Affirmative	
3	Santee Cooper	James M Poston	Abstain	
3	Seattle City Light	Dana Wheelock	Negative	SUPPORTS THIRD PARTY COMMENTS - (Seattle City Light's Paul Hasse's comment)
3	Seminole Electric Cooperative, Inc.	James R Frauen	Negative	SUPPORTS THIRD PARTY COMMENTS - (Seminole Electric Cooperative and NRECA)
3	Sho-Me Power Electric Cooperative	Jeff L Neas	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
3	Snohomish County PUD No. 1	Mark Oens	Negative	SUPPORTS THIRD PARTY COMMENTS - (Sacramento Municipal Utility District ("SMUD"))
3	South Carolina Electric & Gas Co.	Hubert C Young	Affirmative	
3	Southern California Edison Company	Lujuanna Medina	Affirmative	
3	Tacoma Power	Marc Donaldson	Negative	SUPPORTS THIRD PARTY COMMENTS - (Chang Choi)
3	Tampa Electric Co.	Ronald L. Donahey		
3	Tennessee Valley Authority	Ian S Grant	Affirmative	
3	Tri-State Generation & Transmission Association, Inc.	Janelle Marriott	Affirmative	
3	Westar Energy	Bo Jones	Affirmative	
3	Wisconsin Electric Power Marketing	James R Keller	Affirmative	
3	Wisconsin Public Service Corp.	Gregory J Le Grave		
3	Xcel Energy, Inc.	Michael Ibold	Affirmative	
4	Alliant Energy Corp. Services, Inc.	Kenneth Goldsmith	Negative	SUPPORTS THIRD PARTY COMMENTS - (MRO NSRF)
4	Blue Ridge Power Agency	Duane S Dahlquist	Affirmative	
4	City of Austin dba Austin Energy	Reza Ebrahimian	Negative	SUPPORTS THIRD PARTY COMMENTS - (Andrew Gallo)
4	City of Redding	Nicholas Zettel	Negative	SUPPORTS THIRD PARTY COMMENTS - (SMUD & FMPA)
4	City Utilities of Springfield, Missouri	John Allen	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA)
4	Constellation Energy Control & Dispatch, L.L.C.	Margaret Powell	Affirmative	
4	Consumers Energy Company	Tracy Goble	Negative	SUPPORTS THIRD PARTY COMMENTS - (William Waudby)
4	Cowlitz County PUD	Rick Syring	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA)
4	DTE Electric	Daniel Herring	Abstain	
4	Flathead Electric Cooperative	Russ Schneider	Negative	SUPPORTS THIRD PARTY COMMENTS -

				(NRECA)
4	Florida Municipal Power Agency	Frank Gaffney	Negative	COMMENT RECEIVED
4	Fort Pierce Utilities Authority	Cairo Vanegas	Negative	SUPPORTS THIRD PARTY COMMENTS - (Florida Municipal Power Agency)
4	Georgia System Operations Corporation	Guy Andrews	Negative	SUPPORTS THIRD PARTY COMMENTS - (Georgia Transmission Corp)
4	Herb Schrayshuen	Herb Schrayshuen	Affirmative	
4	Illinois Municipal Electric Agency	Bob C. Thomas	Negative	SUPPORTS THIRD PARTY COMMENTS - (Florida Municipal Power Agency)
4	Indiana Municipal Power Agency	Jack Alvey	Negative	SUPPORTS THIRD PARTY COMMENTS - (Florida Municipal Power Agency (FMPA))
4	Integrys Energy Group, Inc.	Christopher Plante	Abstain	
4	Madison Gas and Electric Co.	Joseph DePoorter	Negative	SUPPORTS THIRD PARTY COMMENTS - (MRO NSRF)
4	Modesto Irrigation District	Spencer Tacke	Affirmative	
4	Ohio Edison Company	Douglas Hohlbaugh	Affirmative	
4	Oklahoma Municipal Power Authority	Ashley Stringer	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA)
4	Public Utility District No. 1 of Snohomish County	John D Martinsen	Negative	SUPPORTS THIRD PARTY COMMENTS - (Sacramento Municipal Utility District ("SMUD"))
4	Sacramento Municipal Utility District	Mike Ramirez	Negative	COMMENT RECEIVED
4	Seattle City Light	Hao Li	Negative	SUPPORTS THIRD PARTY COMMENTS - (Seattle City Light's Paul Hasse's comment)
4	Seminole Electric Cooperative, Inc.	Steven R Wallace	Negative	SUPPORTS THIRD PARTY COMMENTS - (SEC supprots the comments submitted by NRECA)
4	South Mississippi Electric Power Association	Steve McElhaney	Negative	SUPPORTS THIRD PARTY COMMENTS - (NRECA)
4	Tacoma Public Utilities	Keith Morisette	Negative	SUPPORTS THIRD PARTY COMMENTS - (Chang Choi)
4	Utility Services, Inc.	Brian Evans-Mongeon	Affirmative	
4	Wisconsin Energy Corp.	Anthony Jankowski		
5	AES Corporation	Leo Bernier	Affirmative	
				SUPPORTS THIRD PARTY

5	Amerenue	Sam Dwyer	Negative	COMMENTS - (Ameren comments)
5	American Electric Power	Thomas Foltz	Affirmative	
5	Arizona Public Service Co.	Scott Takinen	Affirmative	
5	Associated Electric Cooperative, Inc.	Matthew Pacobit	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
5	BC Hydro and Power Authority	Clement Ma	Abstain	
5	Boise-Kuna Irrigation District/dba Lucky peak power plant project	Mike D Kukla		
5	Bonneville Power Administration	Francis J. Halpin	Affirmative	
5	Brazos Electric Power Cooperative, Inc.	Shari Heino	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
5	Calpine Corporation	Hamid Zakery		
5	City and County of San Francisco	Daniel Mason	Abstain	
5	City of Austin dba Austin Energy	Jeanie Doty	Negative	SUPPORTS THIRD PARTY COMMENTS - (Andrew Gallo)
5	City of Redding	Paul A. Cummings	Negative	SUPPORTS THIRD PARTY COMMENTS - (SMUD & FMPA)
5	City of Tallahassee	Karen Webb	Negative	COMMENT RECEIVED
5	City Water, Light & Power of Springfield	Steve Rose	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA Comments)
5	Cleco Power	Stephanie Huffman		
5	Cogentrix Energy Power Management, LLC	Mike D Hirst	Affirmative	
5	Colorado Springs Utilities	Kaleb Brimhall	Negative	SUPPORTS THIRD PARTY COMMENTS - (Group - Colorado Springs Utilities)
5	Con Edison Company of New York	Brian O'Boyle	Affirmative	
5	Consumers Energy Company	David C Greyerbiehl	Negative	SUPPORTS THIRD PARTY COMMENTS - (William Waudby)
5	Cowlitz County PUD	Bob Essex	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA)
5	Dairyland Power Coop.	Tommy Drea	Affirmative	
5	Dominion Resources, Inc.	Mike Garton	Affirmative	
5	DTE Electric	Mark Stefaniak	Abstain	
5	Duke Energy	Dale Q Goodwine	Affirmative	
5	Dynegy Inc.	Dan Roethemeyer	Affirmative	
5	E.ON Climate & Renewables North America, LLC	Dana Showalter		
5	East Kentucky Power Coop.	Stephen Ricker	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
5	EDP Renewables North America LLC	Heather Bowden		
5	El Paso Electric Company	Gustavo Estrada		
5	Empire District Electric Co.	mike l kidwell		
5	Entergy Services, Inc.	Tracey Stubbs		
5	Exelon Nuclear	Mark F Draper	Affirmative	
5	First Wind	John Robertson		
5	FirstEnergy Solutions	Kenneth Dresner	Affirmative	
5	Florida Municipal Power Agency	David Schumann	Negative	COMMENT RECEIVED

5	Great River Energy	Preston L Walsh		
5	Hydro-Québec Production	Roger Dufresne	Abstain	
5	Ingleside Cogeneration LP	Michelle R DAntuono	Negative	COMMENT RECEIVED
5	JEA	John J Babik	Negative	COMMENT RECEIVED
5	Kansas City Power & Light Co.	Brett Holland	Affirmative	
5	Kissimmee Utility Authority	Mike Blough	Negative	SUPPORTS THIRD PARTY COMMENTS - (Florida Municipal Power Agency)
5	Lakeland Electric	James M Howard	Negative	SUPPORTS THIRD PARTY COMMENTS - (Florida Municipal Power Agency)
5	Liberty Electric Power LLC	Daniel Duff	Affirmative	
5	Lincoln Electric System	Dennis Florom	Affirmative	
5	Los Angeles Department of Water & Power	Kenneth Silver	Negative	SUPPORTS THIRD PARTY COMMENTS - (LDWP)
5	Lower Colorado River Authority	Dixie Wells	Negative	COMMENT RECEIVED
5	Luminant Generation Company LLC	Rick Terrill		
5	Manitoba Hydro	Chris Mazur	Affirmative	
5	Massachusetts Municipal Wholesale Electric Company	David Gordon	Abstain	
5	Muscatine Power & Water	Mike Avesing	Affirmative	
5	Nebraska Public Power District	Don Schmit	Negative	SUPPORTS THIRD PARTY COMMENTS - (NPPD)
5	New York Power Authority	Wayne Sipperly	Affirmative	
5	NextEra Energy	Allen D Schriver	Affirmative	
5	North Carolina Electric Membership Corp.	Jeffrey S Brame	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES and NRECA)
5	Northern Indiana Public Service Co.	Michael D Melvin	Affirmative	
5	Oglethorpe Power Corporation	Bernard Johnson	Negative	SUPPORTS THIRD PARTY COMMENTS - (Georgia Transmission Corporation)
5	Oklahoma Gas and Electric Co.	Henry L Staples	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP Comments)
5	Omaha Public Power District	Mahmood Z. Safi	Negative	SUPPORTS THIRD PARTY COMMENTS - (MRO NSRF)
5	Orlando Utilities Commission	Richard K Kinas		
5	Pacific Gas and Electric Company	Alex Chua	Affirmative	
5	Platte River Power Authority	Christopher R Wood	Affirmative	
5	Portland General Electric Co.	Matt E. Jastram		
5	PPL Generation LLC	Annette M Bannon	Affirmative	
5	PSEG Fossil LLC	Tim Kucey	Negative	SUPPORTS THIRD PARTY COMMENTS - (PSEG (Seelke))
5	Public Utility District No. 1 of Lewis County	Steven Grega		
5	Public Utility District No. 2 of Grant County, Washington	Michiko Sell		
5	Puget Sound Energy, Inc.	Lynda Kupfer	Abstain	

5	Sacramento Municipal Utility District	Susan Gill-Zobitz	Negative	COMMENT RECEIVED
5	Salt River Project	William Alkema	Affirmative	
5	Santee Cooper	Lewis P Pierce	Abstain	
5	Seattle City Light	Michael J. Haynes	Negative	SUPPORTS THIRD PARTY COMMENTS - (Paul Haase, Seattle)
5	Snohomish County PUD No. 1	Sam Nietfeld	Negative	SUPPORTS THIRD PARTY COMMENTS - (Sacramento Municipal Utility District ("SMUD"))
5	South Carolina Electric & Gas Co.	Edward Magic		
5	South Feather Power Project	Kathryn Zancanella		
5	Southern California Edison Company	Denise Yaffe		
5	Southern Company Generation	William D Shultz	Negative	SUPPORTS THIRD PARTY COMMENTS - (Southern Company)
5	Tacoma Power	Chris Mattson	Negative	SUPPORTS THIRD PARTY COMMENTS - (Chang Choi)
5	Tampa Electric Co.	RJames Rocha	Abstain	
5	Tenaska, Inc.	Scott M. Helyer		
5	Tennessee Valley Authority	David Thompson	Affirmative	
5	Tri-State Generation & Transmission Association, Inc.	Mark Stein		
5	U.S. Army Corps of Engineers	Melissa Kurtz	Negative	SUPPORTS THIRD PARTY COMMENTS - (MRO NSRF)
5	USDI Bureau of Reclamation	Erika Doot	Negative	COMMENT RECEIVED
5	Westar Energy	Bryan Taggart		
5	Wisconsin Electric Power Co.	Linda Horn	Affirmative	
5	Wisconsin Public Service Corp.	Scott E Johnson		
5	Xcel Energy, Inc.	Mark A Castagneri	Affirmative	
6	AEP Marketing	Edward P. Cox	Affirmative	
6	Ameren Missouri	Robert Quinlivan	Negative	SUPPORTS THIRD PARTY COMMENTS - (Ameren's comments)
6	APS	Randy A. Young	Affirmative	
6	Associated Electric Cooperative, Inc.	Brian Ackermann	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
6	Bonneville Power Administration	Brenda S. Anderson	Affirmative	
6	City of Austin dba Austin Energy	Lisa Martin	Negative	SUPPORTS THIRD PARTY COMMENTS - (Andrew Gallo)
6	City of Redding	Marvin Briggs	Negative	SUPPORTS THIRD PARTY COMMENTS - (SMUD & FMPA)
6	Cleco Power LLC	Robert Hirchak		
6	Colorado Springs Utilities	Shannon Fair	Negative	SUPPORTS THIRD PARTY COMMENTS - (Colorado Springs Utilities)
6	Con Edison Company of New York	David Balban	Affirmative	
6	Constellation Energy Commodities Group	David J Carlson	Affirmative	
6	Dominion Resources, Inc.	Louis S. Slade	Affirmative	

6	Duke Energy	Greg Cecil	Affirmative	
6	FirstEnergy Solutions	Kevin Querry	Affirmative	
6	Florida Municipal Power Agency	Richard L. Montgomery	Negative	COMMENT RECEIVED
6	Florida Municipal Power Pool	Thomas Washburn	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA)
6	Florida Power & Light Co.	Silvia P Mitchell	Affirmative	
6	Kansas City Power & Light Co.	Jessica L Klinghoffer	Affirmative	
6	Lakeland Electric	Paul Shipps		
6	Lincoln Electric System	Eric Ruskamp	Affirmative	
6	Los Angeles Department of Water & Power	Brad Packer	Negative	SUPPORTS THIRD PARTY COMMENTS - (LADWP is voting “Negative” on PRC-005-X for the reason that Requirement 6 seems to be out-of-place i)
6	Lower Colorado River Authority	Michael Shaw	Negative	SUPPORTS THIRD PARTY COMMENTS - (LPPC)
6	Luminant Energy	Brenda Hampton	Affirmative	
6	Manitoba Hydro	Blair Mukanik	Affirmative	
6	Modesto Irrigation District	James McFall	Negative	SUPPORTS THIRD PARTY COMMENTS - (Frank Gaffney (FMPA))
6	New York Power Authority	Shivaz Chopra	Affirmative	
6	Northern California Power Agency	Steve C Hill		
6	Northern Indiana Public Service Co.	Joseph O'Brien	Affirmative	
6	Oglethorpe Power Corporation	Donna Johnson	Negative	SUPPORTS THIRD PARTY COMMENTS - (Georgia Transmission Corporation)
6	Oklahoma Gas and Electric Co.	Jerry Nottnagel	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP)
6	Omaha Public Power District	Douglas Collins	Negative	SUPPORTS THIRD PARTY COMMENTS - (MRO NERC Standards Review Forum)
6	PacifiCorp	Sandra L Shaffer	Affirmative	
6	Platte River Power Authority	Carol Ballantine	Affirmative	
6	Portland General Electric Co.	Shawn P Davis	Negative	SUPPORTS THIRD PARTY COMMENTS - (Angela Gaines, PGE's Comments)
6	Power Generation Services, Inc.	Stephen C Knapp		
6	Powerex Corp.	Gordon Dobson-Mack	Abstain	
6	PPL EnergyPlus LLC	Elizabeth Davis	Affirmative	
6	PSEG Energy Resources & Trade LLC	Peter Dolan	Negative	SUPPORTS THIRD PARTY COMMENTS - (Public Service Enterprise Group)
6	Public Utility District No. 1 of Chelan County	Hugh A. Owen	Abstain	

6	Sacramento Municipal Utility District	Diane Enderby	Negative	COMMENT RECEIVED
6	Salt River Project	William Abraham	Affirmative	
6	Santee Cooper	Michael Brown	Abstain	
6	Seattle City Light	Dennis Sismaet	Negative	SUPPORTS THIRD PARTY COMMENTS - (Paul Haase)
6	Seminole Electric Cooperative, Inc.	Trudy S. Novak		
6	Snohomish County PUD No. 1	Kenn Backholm	Negative	SUPPORTS THIRD PARTY COMMENTS - (Sacramento Municipal Utility District ("SMUD"))
6	Southern California Edison Company	Joseph T Marone	Affirmative	
6	Southern Company Generation and Energy Marketing	John J. Ciza	Negative	SUPPORTS THIRD PARTY COMMENTS - (Southern Company)
6	Tacoma Public Utilities	Michael C Hill	Negative	SUPPORTS THIRD PARTY COMMENTS - (Chang Choi)
6	Tampa Electric Co.	Benjamin F Smith II		
6	Tennessee Valley Authority	Marjorie S. Parsons	Affirmative	
6	Westar Energy	Grant L Wilkerson	Affirmative	
6	Western Area Power Administration - UGP Marketing	Peter H Kinney	Affirmative	
6	Wisconsin Public Service Corp.	David Hathaway		
6	Xcel Energy, Inc.	Peter Colussy	Affirmative	
7	Occidental Chemical	Venona Greaff	Negative	COMMENT RECEIVED
7	Siemens Energy, Inc.	Frank R. McElvain	Affirmative	
8		Roger C Zaklukiewicz		
8		David L Kiguel	Abstain	
8	Massachusetts Attorney General	Frederick R Plett	Affirmative	
8	Volkmann Consulting, Inc.	Terry Volkmann	Negative	SUPPORTS THIRD PARTY COMMENTS - (MRO NSRF)
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson	Affirmative	
9	New York State Public Service Commission	Diane J Barney		
10	Florida Reliability Coordinating Council	Linda C Campbell		
10	Midwest Reliability Organization	Russel Mountjoy	Negative	SUPPORTS THIRD PARTY COMMENTS - (MRO NSRF)
10	New York State Reliability Council	Alan Adamson	Affirmative	
10	Northeast Power Coordinating Council	Guy V. Zito	Affirmative	
10	ReliabilityFirst	Anthony E Jablonski	Affirmative	
10	SERC Reliability Corporation	Joseph W Spencer	Affirmative	
10	Southwest Power Pool RE	Bob Reynolds	Abstain	
10	Texas Reliability Entity, Inc.	Karin Schweitzer	Affirmative	
10	Western Electricity Coordinating Council	Steven L. Rueckert	Abstain	

Non-Binding Poll Results

Project 2017-17.3 Protection System Maintenance – Sudden Pressure Relays

Non-Binding Poll Results	
Non-Binding Poll Name:	Project 2007-17.3 PSMT Sudden Pressure Relays PRC-005-X
Poll Period:	5/23/2014 - 6/3/2014
Total # Opinions:	299
Total Ballot Pool:	349
Summary Results:	85.67% of those who registered to participate provided an opinion or an abstention; 47.77% of those who provided an opinion indicated support for the VRFs and VSLs.

Individual Ballot Pool Results

Segment	Organization	Member	Opinion	NERC Notes
1	Ameren Services	Eric Scott	Abstain	
1	American Electric Power	Paul B Johnson	Abstain	
1	Arizona Public Service Co.	Robert Smith		
1	Associated Electric Cooperative, Inc.	John Bussman	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
1	ATCO Electric	Glen Sutton	Negative	COMMENT RECEIVED
1	Austin Energy	James Armke	Negative	SUPPORTS THIRD PARTY COMMENTS - (Andrew Gallo)
1	Avista Utilities	Heather Rosentrater	Abstain	
1	Balancing Authority of Northern California	Kevin Smith	Negative	COMMENT RECEIVED
1	BC Hydro and Power Authority	Patricia Robertson	Abstain	
1	Bonneville Power Administration	Donald S. Watkins	Affirmative	
1	Bryan Texas Utilities	John C Fontenot	Affirmative	
1	CenterPoint Energy Houston Electric, LLC	John Brockhan	Abstain	
1	Central Electric Power Cooperative	Michael B Bax	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)

1	Central Iowa Power Cooperative	Kevin J Lyons	Negative	SUPPORTS THIRD PARTY COMMENTS - (CIPCO supports the comments submitted by NRECA and ACES.)
1	City and County of San Francisco	Lenise Kimes	Abstain	
1	City of Tacoma, Department of Public Utilities, Light Division, dba Tacoma Power	Chang G Choi	Negative	COMMENT RECEIVED
1	City of Tallahassee	Daniel S Langston	Negative	COMMENT RECEIVED
1	Clark Public Utilities	Jack Stamper	Affirmative	
1	Colorado Springs Utilities	Shawna Speer	Negative	SUPPORTS THIRD PARTY COMMENTS - (Kaleb Brimhall - Colorado Springs Utilities)
1	Consolidated Edison Co. of New York	Christopher L de Graffenried	Affirmative	
1	CPS Energy	Glenn Pressler	Affirmative	
1	Dairyland Power Coop.	Robert W. Roddy	Affirmative	
1	Dayton Power & Light Co.	Hertzel Shamash		
1	Dominion Virginia Power	Larry Nash	Abstain	
1	Duke Energy Carolina	Doug E Hils	Affirmative	
1	East Kentucky Power Coop.	Amber Anderson	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
1	Empire District Electric Co.	Ralph F Meyer		
1	Encari	Steven E Hamburg		
1	Entergy Transmission	Oliver A Burke	Affirmative	
1	FirstEnergy Corp.	William J Smith	Affirmative	
1	Florida Keys Electric Cooperative Assoc.	Dennis Minton	Affirmative	
1	Florida Power & Light Co.	Mike O'Neil	Affirmative	
1	Georgia Transmission Corporation	Jason Snodgrass	Negative	COMMENT RECEIVED
1	Great River Energy	Gordon Pietsch	Affirmative	
1	Hoosier Energy Rural Electric Cooperative, Inc.	Bob Solomon	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
1	Hydro One Networks, Inc.	Muhammed Ali	Affirmative	
1	Hydro-Quebec TransEnergie	Martin Boisvert	Negative	COMMENT RECEIVED
1	Idaho Power Company	Molly Devine	Affirmative	

1	International Transmission Company Holdings Corp	Michael Moltane		
1	JDRJC Associates	Jim D Cyrulewski	Affirmative	
1	JEA	Ted E Hobson	Negative	COMMENT RECEIVED
1	Kansas City Power & Light Co.	Daniel Gibson	Affirmative	
1	Keys Energy Services	Stanley T Rzad		
1	Lakeland Electric	Larry E Watt	Negative	SUPPORTS THIRD PARTY COMMENTS - (Florida Municipal Power Agency (FMPA))
1	Lee County Electric Cooperative	John Chin		
1	Lincoln Electric System	Doug Bantam	Affirmative	
1	Long Island Power Authority	Robert Ganley		
1	Los Angeles Department of Water & Power	faranak sarbaz	Abstain	
1	Lower Colorado River Authority	Martyn Turner	Negative	SUPPORTS THIRD PARTY COMMENTS - (Lower Colorado River Authority)
1	M & A Electric Power Cooperative	William Price	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
1	Manitoba Hydro	Jo-Anne M Ross	Affirmative	
1	MidAmerican Energy Co.	Terry Harbour	Affirmative	
1	Minnkota Power Coop. Inc.	Daniel L Inman	Negative	SUPPORTS THIRD PARTY COMMENTS - (MRO's NERC Standards Review Forum (NSRF))
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
1	National Grid USA	Michael Jones	Affirmative	
1	NB Power Corporation	Alan MacNaughton		
1	Nebraska Public Power District	Jamison Cawley	Abstain	
1	New York Power Authority	Bruce Metruck	Affirmative	
1	Northeast Missouri Electric Power Cooperative	Kevin White	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
1	Northeast Utilities	William Temple	Affirmative	

1	Northern Indiana Public Service Co.	Julaine Dyke	Affirmative	
1	NorthWestern Energy	John Canavan	Affirmative	
1	Ohio Valley Electric Corp.	Scott R Cunningham	Abstain	
1	Oklahoma Gas and Electric Co.	Terri Pyle	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP Standards Review Group comments)
1	Omaha Public Power District	Doug Peterchuck	Negative	SUPPORTS THIRD PARTY COMMENTS - (MRO NSRF)
1	Oncor Electric Delivery	Jen Fiegel	Affirmative	
1	Otter Tail Power Company	Daryl Hanson	Negative	SUPPORTS THIRD PARTY COMMENTS - (we support the comments of the MRO NSRF)
1	Pacific Gas and Electric Company	Bangalore Vijayraghavan	Affirmative	
1	Platte River Power Authority	John C. Collins	Abstain	
1	Portland General Electric Co.	John T Walker	Negative	COMMENT RECEIVED
1	Potomac Electric Power Co.	David Thorne	Abstain	
1	PPL Electric Utilities Corp.	Brenda L Truhe	Affirmative	
1	Public Service Company of New Mexico	Laurie Williams		
1	Public Service Electric and Gas Co.	Kenneth D. Brown	Abstain	
1	Puget Sound Energy, Inc.	Denise M Lietz	Abstain	
1	Rochester Gas and Electric Corp.	John C. Allen	Abstain	
1	Sacramento Municipal Utility District	Tim Kelley	Negative	COMMENT RECEIVED
1	Salt River Project	Robert Kondziolka		
1	SaskPower	Wayne Guttormson		
1	Seattle City Light	Pawel Krupa	Abstain	
1	Seminole Electric Cooperative, Inc.	Glenn Spurlock	Negative	SUPPORTS THIRD PARTY COMMENTS - (Endorses NRECA comments)
1	Snohomish County PUD No. 1	Long T Duong	Negative	SUPPORTS THIRD PARTY COMMENTS - (Sacramento Municipal Utility District ("SMUD"))

1	South Carolina Electric & Gas Co.	Tom Hanzlik	Affirmative	
1	South Carolina Public Service Authority	Shawn T Abrams	Abstain	
1	Southern California Edison Company	Steven Mavis	Affirmative	
1	Southern Company Services, Inc.	Robert A. Schaffeld	Negative	SUPPORTS THIRD PARTY COMMENTS - (Southern Company)
1	Southern Illinois Power Coop.	William Hutchison	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
1	Southwest Transmission Cooperative, Inc.	John Shaver	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
1	Sunflower Electric Power Corporation	Noman Lee Williams	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
1	Tampa Electric Co.	Beth Young		
1	Tennessee Valley Authority	Howell D Scott	Abstain	
1	Tri-State Generation & Transmission Association, Inc.	Tracy Sliman	Affirmative	
1	Tucson Electric Power Co.	John Tolo		
1	U.S. Bureau of Reclamation	Richard T Jackson	Negative	COMMENT RECEIVED
1	United Illuminating Co.	Jonathan Appelbaum	Affirmative	
1	Vermont Electric Power Company, Inc.	Kim Moulton	Affirmative	
1	Westar Energy	Allen Klassen	Affirmative	
1	Western Area Power Administration	Lloyd A Linke	Affirmative	
1	Wolverine Power Supply Coop., Inc.	Michelle Clements	Abstain	
2	BC Hydro	Venkataramakrishnan Vinnakota	Abstain	
2	California ISO	Rich Vine	Negative	SUPPORTS THIRD PARTY COMMENTS - (ISO/RTO Standards Review Committee)
2	Electric Reliability Council of Texas, Inc.	Cheryl Moseley	Negative	SUPPORTS THIRD PARTY COMMENTS - (IRC SRC)
2	Independent Electricity System Operator	Leonard Kula	Affirmative	
2	ISO New England, Inc.	Matthew F Goldberg	Abstain	
2	MISO	Marie Knox	Abstain	
2	New York Independent System Operator	Gregory Campoli	Abstain	
2	PJM Interconnection, L.L.C.	stephanie monzon	Negative	SUPPORTS THIRD PARTY

				COMMENTS - (SRC)
2	Southwest Power Pool, Inc.	Charles H. Yeung	Abstain	
3	AEP	Michael E Deloach	Abstain	
3	Alabama Power Company	Robert S Moore	Negative	SUPPORTS THIRD PARTY COMMENTS - (Southern Company)
3	Ameren Corp.	David J Jendras	Abstain	
3	APS	Sarah Kist	Affirmative	
3	Associated Electric Cooperative, Inc.	Todd Bennett	Negative	SUPPORTS THIRD PARTY COMMENTS - (Associated Electric Cooperative Inc)
3	Avista Corp.	Scott J Kinney	Abstain	
3	BC Hydro and Power Authority	Pat G. Harrington	Abstain	
3	Bonneville Power Administration	Rebecca Berdahl	Affirmative	
3	Central Electric Power Cooperative	Adam M Weber	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
3	City of Anaheim Public Utilities Department	Dennis M Schmidt		
3	City of Austin dba Austin Energy	Andrew Gallo	Negative	COMMENT RECEIVED
3	City of Clewiston	Lynne Mila	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA)
3	City of Farmington	Linda R Jacobson	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA)
3	City of Green Cove Springs	Mark Schultz	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA)
3	City of Tallahassee	Bill R Fowler	Negative	COMMENT RECEIVED
3	Colorado Springs Utilities	Jean Mueller	Affirmative	
3	Consolidated Edison Co. of New York	Peter T Yost	Affirmative	
3	Consumers Energy Company	Gerald G Farringer		
3	Cowlitz County PUD	Russell A Noble	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA)
3	CPS Energy	Jose Escamilla	Affirmative	
3	Dominion Resources, Inc.	Connie B Lowe	Abstain	
3	DTE Electric	Kent Kujala	Abstain	

3	East Kentucky Power Coop.	Patrick Woods	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
3	FirstEnergy Corp.	Cindy E Stewart	Affirmative	
3	Florida Keys Electric Cooperative	Tom B Anthony	Affirmative	
3	Florida Municipal Power Agency	Joe McKinney	Negative	COMMENT RECEIVED
3	Florida Power Corporation	Lee Schuster	Affirmative	
3	Georgia System Operations Corporation	Scott McGough	Negative	SUPPORTS THIRD PARTY COMMENTS - (Georgia Transmission Corporation)
3	Great River Energy	Brian Glover	Affirmative	
3	Hydro One Networks, Inc.	Ayesha Sabouba	Affirmative	
3	JEA	Garry Baker	Negative	SUPPORTS THIRD PARTY COMMENTS - (JEA)
3	Kansas City Power & Light Co.	Joshua D Bach	Affirmative	
3	Kissimmee Utility Authority	Gregory D Woessner		
3	Lakeland Electric	Mace D Hunter	Negative	SUPPORTS THIRD PARTY COMMENTS - (Florida Municipal Power Agency)
3	Lee County Electric Cooperative	David A Hadzima		
3	Lincoln Electric System	Jason Fortik	Affirmative	
3	Los Angeles Department of Water & Power	Mike Anctil	Abstain	
3	Louisville Gas and Electric Co.	Charles A. Freibert		
3	Manitoba Hydro	Greg C. Parent	Affirmative	
3	MidAmerican Energy Co.	Thomas C. Mielnik	Affirmative	
3	Modesto Irrigation District	Jack W Savage	Abstain	
3	Muscatine Power & Water	John S Bos	Affirmative	
3	National Grid USA	Brian E Shanahan	Affirmative	
3	Nebraska Public Power District	Tony Eddleman	Abstain	
3	New York Power Authority	David R Rivera	Affirmative	
3	Northern Indiana Public Service Co.	Ramon J Barany	Affirmative	
3	NW Electric Power Cooperative, Inc.	David McDowell	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
3	Ocala Utility Services	Randy Hahn	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA)
3	Oklahoma Gas and Electric Co.	Donald Hargrove	Negative	SUPPORTS THIRD PARTY

				COMMENTS - (SPP Comments)
3	Omaha Public Power District	Blaine R. Dinwiddie	Negative	SUPPORTS THIRD PARTY COMMENTS - (MRO NSRF)
3	Orlando Utilities Commission	Ballard K Mutters	Abstain	
3	Owensboro Municipal Utilities	Thomas T Lyons	Abstain	
3	Pacific Gas and Electric Company	John H Hagen	Affirmative	
3	Platte River Power Authority	Terry L Baker	Abstain	
3	PNM Resources	Michael Mertz		
3	Portland General Electric Co.	Thomas G Ward	Negative	SUPPORTS THIRD PARTY COMMENTS - (PGE's comments)
3	Public Service Electric and Gas Co.	Jeffrey Mueller	Abstain	
3	Puget Sound Energy, Inc.	Mariah R Kennedy	Abstain	
3	Rutherford EMC	Thomas Haire	Negative	SUPPORTS THIRD PARTY COMMENTS - (NRECA)
3	Sacramento Municipal Utility District	James Leigh-Kendall	Negative	COMMENT RECEIVED
3	Salt River Project	John T. Underhill	Affirmative	
3	Santee Cooper	James M Poston	Abstain	
3	Seminole Electric Cooperative, Inc.	James R Frauen	Negative	SUPPORTS THIRD PARTY COMMENTS - (Seminole Electric Cooperative and NRECA)
3	Sho-Me Power Electric Cooperative	Jeff L Neas	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
3	Snohomish County PUD No. 1	Mark Oens	Negative	SUPPORTS THIRD PARTY COMMENTS - (Sacramento Municipal Utility District ("SMUD"))
3	South Carolina Electric & Gas Co.	Hubert C Young	Affirmative	
3	Southern California Edison Company	Lujuanna Medina	Affirmative	
3	Tacoma Power	Marc Donaldson	Negative	SUPPORTS THIRD PARTY COMMENTS - (Chang Choi)
3	Tampa Electric Co.	Ronald L. Donahey		
3	Tennessee Valley Authority	Ian S Grant	Abstain	

3	Tri-State Generation & Transmission Association, Inc.	Janelle Marriott	Affirmative	
3	Westar Energy	Bo Jones	Affirmative	
3	Xcel Energy, Inc.	Michael Ibold	Abstain	
4	Alliant Energy Corp. Services, Inc.	Kenneth Goldsmith	Negative	SUPPORTS THIRD PARTY COMMENTS - (MRO NSRF)
4	Blue Ridge Power Agency	Duane S Dahlquist	Affirmative	
4	City of Austin dba Austin Energy	Reza Ebrahimian	Negative	SUPPORTS THIRD PARTY COMMENTS - (Andrew Gallo)
4	City Utilities of Springfield, Missouri	John Allen	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA)
4	Consumers Energy Company	Tracy Goble	Negative	SUPPORTS THIRD PARTY COMMENTS - (William Waudby)
4	Cowlitz County PUD	Rick Syring	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA)
4	DTE Electric	Daniel Herring	Abstain	
4	Flathead Electric Cooperative	Russ Schneider	Negative	SUPPORTS THIRD PARTY COMMENTS - (NRECA)
4	Florida Municipal Power Agency	Frank Gaffney	Negative	COMMENT RECEIVED
4	Georgia System Operations Corporation	Guy Andrews	Negative	SUPPORTS THIRD PARTY COMMENTS - (Georgia Transmission Corp)
4	Herb Schrayshuen	Herb Schrayshuen	Affirmative	
4	Illinois Municipal Electric Agency	Bob C. Thomas	Abstain	
4	Indiana Municipal Power Agency	Jack Alvey	Negative	SUPPORTS THIRD PARTY COMMENTS - (Florida Municipal Power Agency (FMPA))
4	Integrys Energy Group, Inc.	Christopher Plante	Abstain	
4	Madison Gas and Electric Co.	Joseph DePoorter	Abstain	
4	Ohio Edison Company	Douglas Hohlbaugh	Affirmative	

4	Public Utility District No. 1 of Snohomish County	John D Martinsen	Negative	SUPPORTS THIRD PARTY COMMENTS - (Sacramento Municipal Utility District ("SMUD"))
4	Sacramento Municipal Utility District	Mike Ramirez	Negative	COMMENT RECEIVED
4	Seminole Electric Cooperative, Inc.	Steven R Wallace	Negative	SUPPORTS THIRD PARTY COMMENTS - (SEC supports the commnets submitted by NRECA)
4	South Mississippi Electric Power Association	Steve McElhaney	Negative	SUPPORTS THIRD PARTY COMMENTS - (NRECA)
4	Tacoma Public Utilities	Keith Morisette	Negative	SUPPORTS THIRD PARTY COMMENTS - (Chang Choi)
4	Utility Services, Inc.	Brian Evans-Mongeon	Abstain	
4	Wisconsin Energy Corp.	Anthony Jankowski		
5	AES Corporation	Leo Bernier	Affirmative	
5	Amerenue	Sam Dwyer	Abstain	
5	American Electric Power	Thomas Foltz	Abstain	
5	Arizona Public Service Co.	Scott Takinen	Affirmative	
5	Associated Electric Cooperative, Inc.	Matthew Pacobit	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
5	BC Hydro and Power Authority	Clement Ma	Abstain	
5	Boise-Kuna Irrigation District/dba Lucky peak power plant project	Mike D Kukla		
5	Bonneville Power Administration	Francis J. Halpin	Affirmative	
5	Brazos Electric Power Cooperative, Inc.	Shari Heino	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
5	Calpine Corporation	Hamid Zakery		
5	City and County of San Francisco	Daniel Mason	Abstain	
5	City of Austin dba Austin Energy	Jeanie Doty	Negative	SUPPORTS THIRD PARTY COMMENTS - (Andrew Gallo)
5	City of Tallahassee	Karen Webb	Negative	COMMENT RECEIVED

5	City Water, Light & Power of Springfield	Steve Rose	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA Comments)
5	Cleco Power	Stephanie Huffman		
5	Cogentrix Energy Power Management, LLC	Mike D Hirst	Affirmative	
5	Colorado Springs Utilities	Kaleb Brimhall	Negative	SUPPORTS THIRD PARTY COMMENTS - (Group - Colorado Springs Utilities)
5	Con Edison Company of New York	Brian O'Boyle	Affirmative	
5	Consumers Energy Company	David C Greyerbiehl	Negative	SUPPORTS THIRD PARTY COMMENTS - (William Waudby)
5	Cowlitz County PUD	Bob Essex	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA)
5	Dairyland Power Coop.	Tommy Drea	Affirmative	
5	Dominion Resources, Inc.	Mike Garton	Abstain	
5	DTE Electric	Mark Stefaniak	Abstain	
5	Duke Energy	Dale Q Goodwine	Affirmative	
5	Dynegy Inc.	Dan Roethemeyer	Affirmative	
5	E.ON Climate & Renewables North America, LLC	Dana Showalter		
5	East Kentucky Power Coop.	Stephen Ricker	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
5	EDP Renewables North America LLC	Heather Bowden		
5	El Paso Electric Company	Gustavo Estrada		
5	Entergy Services, Inc.	Tracey Stubbs		
5	First Wind	John Robertson		
5	FirstEnergy Solutions	Kenneth Dresner	Affirmative	
5	Florida Municipal Power Agency	David Schumann	Negative	COMMENT RECEIVED
5	Great River Energy	Preston L Walsh		
5	Hydro-Québec Production	Roger Dufresne	Abstain	
5	Ingleside Cogeneration LP	Michelle R DAntuono	Negative	COMMENT RECEIVED
5	JEA	John J Babik	Negative	COMMENT RECEIVED
5	Kansas City Power & Light Co.	Brett Holland	Affirmative	
5	Kissimmee Utility Authority	Mike Blough	Negative	SUPPORTS THIRD PARTY COMMENTS -

				(Florida Municipal Power Agency)
5	Liberty Electric Power LLC	Daniel Duff	Affirmative	
5	Lincoln Electric System	Dennis Florom	Affirmative	
5	Los Angeles Department of Water & Power	Kenneth Silver	Abstain	
5	Lower Colorado River Authority	Dixie Wells	Negative	COMMENT RECEIVED
5	Luminant Generation Company LLC	Rick Terrill		
5	Manitoba Hydro	Chris Mazur	Affirmative	
5	Massachusetts Municipal Wholesale Electric Company	David Gordon	Abstain	
5	Muscatine Power & Water	Mike Avesing	Affirmative	
5	Nebraska Public Power District	Don Schmit	Abstain	
5	New York Power Authority	Wayne Sipperly	Affirmative	
5	NextEra Energy	Allen D Schriver	Affirmative	
5	North Carolina Electric Membership Corp.	Jeffrey S Brame	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES and NRECA)
5	Northern Indiana Public Service Co.	Michael D Melvin	Affirmative	
5	Oglethorpe Power Corporation	Bernard Johnson	Negative	SUPPORTS THIRD PARTY COMMENTS - (Georgia Transmission Corporation)
5	Oklahoma Gas and Electric Co.	Henry L Staples	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP Comments)
5	Omaha Public Power District	Mahmood Z. Safi	Negative	SUPPORTS THIRD PARTY COMMENTS - (MRO NSRF)
5	Orlando Utilities Commission	Richard K Kinas		
5	Pacific Gas and Electric Company	Alex Chua	Affirmative	
5	Platte River Power Authority	Christopher R Wood	Abstain	
5	Portland General Electric Co.	Matt E. Jastram		
5	PPL Generation LLC	Annette M Bannon	Affirmative	
5	PSEG Fossil LLC	Tim Kucey	Abstain	
5	Public Utility District No. 1 of Lewis County	Steven Grega		
5	Public Utility District No. 2 of Grant County, Washington	Michiko Sell		
5	Puget Sound Energy, Inc.	Lynda Kupfer	Abstain	
5	Sacramento Municipal Utility District	Susan Gill-Zobitz	Negative	COMMENT RECEIVED

5	Salt River Project	William Alkema	Affirmative	
5	Santee Cooper	Lewis P Pierce	Abstain	
5	Seattle City Light	Michael J. Haynes	Abstain	
5	Snohomish County PUD No. 1	Sam Nietfeld	Negative	SUPPORTS THIRD PARTY COMMENTS - (Sacramento Municipal Utility District ("SMUD"))
5	South Carolina Electric & Gas Co.	Edward Magic	Affirmative	
5	South Feather Power Project	Kathryn Zancanella		
5	Southern California Edison Company	Denise Yaffe		
5	Southern Company Generation	William D Shultz	Negative	SUPPORTS THIRD PARTY COMMENTS - (Southern Company)
5	Tacoma Power	Chris Mattson	Negative	SUPPORTS THIRD PARTY COMMENTS - (Chang Choi)
5	Tampa Electric Co.	RJames Rocha	Abstain	
5	Tenaska, Inc.	Scott M. Helyer		
5	Tennessee Valley Authority	David Thompson	Abstain	
5	Tri-State Generation & Transmission Association, Inc.	Mark Stein		
5	U.S. Army Corps of Engineers	Melissa Kurtz	Negative	SUPPORTS THIRD PARTY COMMENTS - (MRO NSRF)
5	USDI Bureau of Reclamation	Erika Doot	Negative	COMMENT RECEIVED
5	Wisconsin Public Service Corp.	Scott E Johnson		
5	Xcel Energy, Inc.	Mark A Castagneri	Affirmative	
6	AEP Marketing	Edward P. Cox	Abstain	
6	Ameren Missouri	Robert Quinlivan	Abstain	
6	APS	Randy A. Young	Affirmative	
6	Associated Electric Cooperative, Inc.	Brian Ackermann	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
6	Bonneville Power Administration	Brenda S. Anderson	Affirmative	
6	City of Austin dba Austin Energy	Lisa Martin	Negative	SUPPORTS THIRD PARTY COMMENTS - (Andrew Gallo)
6	Cleco Power LLC	Robert Hirchak		
6	Colorado Springs Utilities	Shannon Fair	Negative	SUPPORTS THIRD PARTY COMMENTS -

				(Colorado Springs Utilities)
6	Con Edison Company of New York	David Balban	Affirmative	
6	Duke Energy	Greg Cecil	Affirmative	
6	FirstEnergy Solutions	Kevin Querry	Affirmative	
6	Florida Municipal Power Agency	Richard L. Montgomery	Negative	COMMENT RECEIVED
6	Florida Municipal Power Pool	Thomas Washburn	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA)
6	Florida Power & Light Co.	Silvia P Mitchell	Affirmative	
6	Kansas City Power & Light Co.	Jessica L Klinghoffer	Affirmative	
6	Lakeland Electric	Paul Shipps		
6	Lincoln Electric System	Eric Ruskamp	Affirmative	
6	Los Angeles Department of Water & Power	Brad Packer	Negative	SUPPORTS THIRD PARTY COMMENTS - (LADWP is voting “Negative” on PRC-005-X for the reason that Requirement 6 seems to be out-of-place i)
6	Lower Colorado River Authority	Michael Shaw	Negative	SUPPORTS THIRD PARTY COMMENTS - (LPPC)
6	Luminant Energy	Brenda Hampton	Affirmative	
6	Manitoba Hydro	Blair Mukanik	Affirmative	
6	Modesto Irrigation District	James McFall	Abstain	
6	New York Power Authority	Shivaz Chopra	Affirmative	
6	Northern California Power Agency	Steve C Hill		
6	Northern Indiana Public Service Co.	Joseph O'Brien	Affirmative	
6	Oglethorpe Power Corporation	Donna Johnson	Negative	SUPPORTS THIRD PARTY COMMENTS - (Georgia Transmission Corporation)
6	Oklahoma Gas and Electric Co.	Jerry Nottnagel	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP)
6	Omaha Public Power District	Douglas Collins	Negative	SUPPORTS THIRD PARTY COMMENTS - (MRO NERC

				Standards Review Forum)
6	PacifiCorp	Sandra L Shaffer	Abstain	
6	Platte River Power Authority	Carol Ballantine	Abstain	
6	Portland General Electric Co.	Shawn P Davis	Negative	SUPPORTS THIRD PARTY COMMENTS - (Angela Gaines, PGE's Comments)
6	Power Generation Services, Inc.	Stephen C Knapp		
6	Powerex Corp.	Gordon Dobson-Mack	Abstain	
6	PPL EnergyPlus LLC	Elizabeth Davis	Affirmative	
6	PSEG Energy Resources & Trade LLC	Peter Dolan	Abstain	
6	Sacramento Municipal Utility District	Diane Enderby	Negative	COMMENT RECEIVED
6	Salt River Project	William Abraham	Affirmative	
6	Santee Cooper	Michael Brown	Abstain	
6	Seattle City Light	Dennis Sismaet	Negative	SUPPORTS THIRD PARTY COMMENTS - (Paul Haase)
6	Seminole Electric Cooperative, Inc.	Trudy S. Novak		
6	Snohomish County PUD No. 1	Kenn Backholm	Negative	SUPPORTS THIRD PARTY COMMENTS - (Sacramento Municipal Utility District ("SMUD"))
6	Southern California Edison Company	Joseph T Marone	Affirmative	
6	Southern Company Generation and Energy Marketing	John J. Ciza	Negative	SUPPORTS THIRD PARTY COMMENTS - (Southern Company)
6	Tacoma Public Utilities	Michael C Hill	Negative	SUPPORTS THIRD PARTY COMMENTS - (Chang Choi)
6	Tampa Electric Co.	Benjamin F Smith II		
6	Tennessee Valley Authority	Marjorie S. Parsons	Abstain	
6	Western Area Power Administration - UGP Marketing	Peter H Kinney	Affirmative	
7	Exxon Mobil	Jay Barnett		
7	Occidental Chemical	Venona Greaff	Negative	COMMENT RECEIVED
8		David L Kiguel	Abstain	
8		Roger C Zaklukiewicz		
8	Massachusetts Attorney General	Frederick R Plett	Affirmative	

8	Volkmann Consulting, Inc.	Terry Volkmann	Negative	SUPPORTS THIRD PARTY COMMENTS - (MRO NSRF)
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson	Affirmative	
10	Florida Reliability Coordinating Council	Linda C Campbell		
10	Midwest Reliability Organization	Russel Mountjoy	Negative	SUPPORTS THIRD PARTY COMMENTS - (MRO NSRF)
10	New York State Reliability Council	Alan Adamson	Affirmative	
10	Northeast Power Coordinating Council	Guy V. Zito	Affirmative	
10	ReliabilityFirst	Anthony E Jablonski	Affirmative	
10	SERC Reliability Corporation	Joseph W Spencer	Affirmative	
10	Southwest Power Pool RE	Bob Reynolds	Abstain	
10	Texas Reliability Entity, Inc.	Karin Schweitzer	Affirmative	
10	Western Electricity Coordinating Council	Steven L. Rueckert	Abstain	

Individual or group. (56 Responses)
Name (35 Responses)
Organization (35 Responses)
Group Name (21 Responses)
Lead Contact (21 Responses)
Question 1 (48 Responses)
Question 1 Comments (48 Responses)
Question 2 (45 Responses)
Question 2 Comments (48 Responses)
Question 3 (44 Responses)
Question 3 Comments (48 Responses)
Question 4 (40 Responses)
Question 4 Comments (48 Responses)
Question 5 (43 Responses)
Question 5 Comments (48 Responses)

Group
Northeast Power Coordinating Council
Guy Zito
Yes
The definition of sudden pressure relaying is clear and limits the scope of the standard to relays that trip interrupting devices. However, Section 4.2 Facilities, 4.2.1 reads: “Protection Systems and Sudden Pressure Relaying that are installed for the purpose of detecting Faults on BES Elements (lines, buses, transformers, etc.)” This is confusing in that it refers to relays that detect faults regardless of whether they trip interrupting devices or not. Because Sudden Pressure Relays can be used just to alarm, suggest creating a new 4.2.x that says “Sudden Pressure Relaying installed for the purpose of detecting Faults and initiating the automatic operation of interrupting device(s) to isolate the equipment it is monitoring.” In the Applicability Section, Items 4.2 and following should be removed and incorporated as definitions because the NERC Standard Processes Manual (Version 3.0, June 26, 2013, page 7) defines Applicability: “Applicability: Identifies which entities are assigned reliability requirements. The specific Functional Entities and Facilities to which the Reliability Standard applies.” From the NERC Glossary: “Facility--A set of electrical equipment that operates as a single Bulk Electric System Element (e.g., a line, a generator, a shunt compensator, transformer, etc.)”
Yes
We support the addition of the Balancing Authority to PRC-005-X. Transmission Owners, Generation Owners, and Distribution Providers should receive notification directly from the Balancing Authorities to accurately apply Section 4.2.6 Applicability. The Balancing Authority is the entity that maintains the information and should have the responsibility to provide this information to the applicable entities. (Please see the Rationale box for R6 in the draft standard.) Transmission Owners, Generator Owners, and Distribution Providers should not be expected to monitor a database such as GADS or some other proposed list of all Balancing Authorities that identifies the largest BES generating unit within each Balancing Authority Area. The information should be provided directly to the Transmission Owners, Generator Owners, and Distribution Providers by their Balancing Authority. Applicability Section 4.2.6.1 calls for “Automatic Reclosing applied on the terminals of Elements connected to the BES bus…”. Is the intention to have automatic reclosing on all Elements? In Applicability Section 4.2.6.2, what is the basis for the 10 circuit-mile parameter? The Standard Drafting Team should take advantage of the fact that even thought the content of Rationale Boxes is not auditable, Rationale Boxes stay with the standard and can be used to convey information about a requirement, or section of a standard. For example, regarding the Rationale for R3 Part 3.1 and sub-Part 3.1.1, in addition to explaining whether the PSMP should be in the Standard or the Implementation Plan, it should also explain why newly identified Sudden Pressure Relaying is not included in the Parts and sub-Parts of R3.
No

No
Yes
Because Automatic Reclosing and Sudden Pressure Relaying are terms likely to be used in other standards, their inclusion in the NERC Glossary should be considered to prevent confusion and ensure consistency. The wording in the Rationale Box for R6 should reference Section 4.2.6, not Section 4.2.7. The footnote on page 4 also incorrectly references Section 4.2.7. Sub-Parts 3.1.1, 3.1.2, 4.1.1, and 4.1.2 address time and documentation requirements. The Rationale Boxes for R3 and R4 explain the consideration of putting these sub-Parts in an implementation plan or within the standard. The requirements should address a standard of performance, not a time period to implement, not a statement to address the provision of documentation. The language should be moved to the Measures. Requirements R3 and R4 are written specifically for Automatic Reclosing components. The rationale is because the BA may notify the TO of a new BES element subject to the Automatic Reclosing requirements. However, this process of notification is not unique to Automatic Reclosing. The RC may identify new BES elements a TO was not aware of due to a reconfiguration in another area. In these instances there should be some allowance to incorporate the new protection systems. The solution the SDT has developed for Automatic Reclosing could easily be expanded to include all Protection Systems, Automatic Reclosing and Sudden Pressure Relaying.
Group
FirstEnergy
Cindy Stewart
No
Yes
FirstEnergy supports the addition of Balancing Authority to the Applicability and notification of the largest BES generating unit.
Yes
FirstEnergy supports the change in data retention to one performance cycle instead of two.
No
No
Individual
Michelle R. D'Antuono
Ingleside Cogeneration LP
Yes
Ingleside Cogeneration LP (ICLP) believes that the drafting team has done an excellent job of precisely identifying the applicable relay types and control circuitry subject to PRC-005-X. In addition, we have no argument with the maintenance activities and intervals associated with Sudden Pressure Relaying that have been established in this initial draft. However, we do not understand the need to update the definition of “Protection System Maintenance Program (PSMP)” in the NERC Glossary. If the intent is to clarify that reclosers and sudden pressure relays are also a form of Protection System, then it follows that the definition of “Protection System” will need to be updated as well. That will not be an easy task – as those of us who participated in the last modification to that Glossary term can relate. In addition, the inferred reference in PSMP to standard-specific definitions of “Automatic Reclosing”, “Sudden Pressure Relaying”, and “Component” is not obvious. A term in the NERC Glossary should not require an examination of a completely different document in order to decipher its full meaning. Nor does it seem that there is a pressing need to clarify that the PSMP applies to those systems – the requirements in PRC-005-X make it clear that it does. Similarly, ICLP does not understand the urgency to replace the standard-specific definition of “Component”. We recall exhaustive back-and-forth during the development of PRC-005-2 that the maintenance of Control Circuitry was an item of direct concern to the industry (and to us). Historically, CEAs did not

always understand the complexities involved with Control Circuitry maintenance and had to be convinced that several separate tests are often needed to fully validate end-to-end functional performance. By moving the language to the guidance documents, ICLP believes that the issue will recur. In our view, the changes to the definitions of “PSMP” and “Component” should be deferred at this point. They do not resolve a reliability gap, nor do they eliminate ambiguities in the standard. If the drafting team feels strongly otherwise, the issues can be captured and revisited during the 5 year review of the PRC standards.
Yes
As a Generator Owner, ICLP strongly supports the requirement for Balancing Authorities to provide the gross capacity of the largest BES generating unit within their operating footprint. We will rely upon this information to determine whether or not the recloser maintenance requirements apply to our Facilities. However, we would not want to see a notification whenever the unit in question is taken offline for routine maintenance or other short-term action. Perhaps the time horizon indicator of “Operations Planning” suffices, but ICLP would prefer direct language in the requirement itself.
No
No
No
Group
PacifiCorp
Sandra Shaffer
No
No
No
No
Yes
: Page 9/39, R6 currently states, “Each Balancing Authority shall, at least once every calendar year with not more than 15 calendar months between notifications, notify each Transmission Owner, Generator Owner, and Distribution Provider within its Balancing Authority Area of the gross capacity, in MW or MVA, of the largest BES generating unit within the Balancing Authority Area.” 1. Does the term “gross capacity” refer to nameplate capacity or something else? 2. Does the term “unit” refer to an individual generating unit or overall plant?
Individual
Mark Wilson
Independent Electricity System Operator
No
Yes
We do not support adding BA to the standard. As proposed, the BA is only required (in Requirement R6) to notify others of the largest BES generating unit in its Area. This information is used by owners of the automatic reclosing (A/R) facilities to determine whether or not their A/R facilities meet the Applicability criteria for inclusion in their maintenance program. The status of the largest generating unit in a BA Area does not change often, and can easily be provided in a database such as GADS. Alternatively, NERC may want to establish a list of all BAs along with their respective total installed generating capacities and largest generating units. This will serve the purpose that Requirement R6 is intended to accomplish. In our view, Reliability Standards are developed with an objective to

achieve consistent behavior or targeted performance outcome. Requiring a BA to provide data (that can be obtained from other easier means) does not align with the intended purpose of developing Reliability Standards. We suggest BA and R6 be removed, and the information related to the largest generating unit in a BA area be provided via other means such as RoP 1600 or GADS.
Yes
We generally agree with the proposed changes except the addition of the retention requirement for R6.
Individual
Venona Greaff
Occidental Chemical Corporation
Individual
Jack Stamper
Clark Public Utilities
No
No
No
Yes
The proposed Table 5 states testing requirements for the control circuitry as "Control circuitry associated with Sudden Pressure Relaying from the fault pressure relay to the interrupting device trip coil(s)." This language seems to imply breaker trip coils. The Supplementary Reference and FAQ contains an FAQ for this testing that reads "Sudden Pressure Relaying control circuitry is now specifically mentioned in the maintenance tables, do we have to trip our circuit breaker specifically from the trip output of the sudden pressure relay? No. Verification may be by breaker tripping, but may be verified in overlapping segments with the Protection System control circuitry." I would recommend that you indicate somewhere that where a Sudden Pressure Relay control circuitry operates a lockout relay (which I believe is common) that testing need only occur between the Sudden Pressure Relay and the lockout relay and that testing of the lockout relay and any control circuitry from the lockout relay to breakers or other protection devices is provided for in Table 1-5.
No
Individual
Patti Metro
National Rural Electric Cooperative Association
No
Yes
NRECA does not agree with the inclusion of the Balancing Authority as an applicable entity in this version of the draft standard and the associated addition of R6 requiring that “Each Balancing Authority shall, at least once every calendar year with not more than 15 calendar months between notifications, notify each Transmission Owner, Generator Owner, and Distribution Provider within its Balancing Authority Area of the gross capacity, in MW or MVA, of the largest BES generating unit within the Balancing Authority Area. The drafting team has not provided sufficient technical justification to warrant the inclusion of Balancing Authorities as an applicable entity in a Protection System Maintenance standard and the inclusion of the associated R6 is onerous and meets the criteria to be classified as an “administrative” requirement. In addition, the SDT improperly cited 4.2.7 within R6 Rationale since 4.2.7 is not a section in the applicability of this standard. The applicable entities in this standard should only be those entities that own and maintain the

Protection Systems described in the draft standard not an entity responsible “ that integrates resource plans ahead of time, maintains load-interchange-generation balance within a Balancing Authority Area, and supports Interconnection frequency in real time”.
No
No
No
Group
Colorado Springs Utilities
Kaleb Brimhall
Yes
Sudden pressure relays, which do trip some transformers, are not important in preventing “instability, cascading, or separation.” CSU believes that the inclusion of sudden pressure relays in the NERC Standards will not improve the reliability of the BES, and are outside the FPA Section 215 jurisdiction. The following are some additional notes on this topic: • Many transformers are not protected using sudden pressure relays. In fact, due to the sensitivity of sudden pressure relays to vibration, some areas of the country purposefully do not use sudden pressure relays for transformer protection. • Many transformers that are protected using sudden pressure relays use a guarded trip scheme. For example, in order for the sudden pressure relay to trip the transformer there must also be another condition present such as an over current or differential trip. • There is not a consistent application of sudden pressure relays in the industry, many transformers do not utilize these relays for protection, and no requirements exist to have sudden pressure relays. CSU believes that including them in a standard will discourage their use and/or encourage those that currently use them to remove them from their protection scheme. Sudden pressure relays when applied correctly can be an asset in transformer protection, but are not important in preventing “instability, cascading, or separation.”
Yes
We do not think that this requirement is necessary. It is the responsibility of the entity establishing compliance processes to reach out and verify that they have the right data to ensure compliance. If this requirement is to stay. We propose that this requirement is modified to reflect that upon request the BA shall provide this information within X timeframe. This will prevent unnecessary paperwork.
Yes
We like the revised data retention requirements, less is better when it comes to paperwork that draws resources away from the true compliance work.
No
No
Individual
Tom Haire
Rutherford EMC
Individual
David Thorne
Pepco Holdings Inc.
No
No
No

No
No
Individual
Ayesha Sabouba
Hydro One
Individual
Thomas Foltz
American Electric Power
Yes
The current applicability wording should be revised to more clearly indicate the applicability of sudden pressure relaying to dispersed generation facilities. The reader could make two very different interpretations of applicability: 1) 4.2.5.2 addresses transformers between the aggregation point and the BES that work effectively as GSU's while 4.2.5.3 addresses transformers located at the individual generating resources. Or 2) 4.2.5.2 addresses GSU transformers on traditional non-dispersed generation while 4.2.5.3 addresses all transformers on dispersed generation, none of which are required to maintain sudden pressure relaying. We believe the standard's applicability would be clearer by specifically listing the aggregation point at which sudden pressure relaying must be maintained at dispersed generation facilities. AEP believes Sudden Pressure Relaying should only be considered on collector systems transformers where the generation aggregate value is 75MVA and greater.
Yes
The rationale for R6 references Section 4.2.7, Applicability. The Applicability section does not contain a Section 4.2.7 and we believe the reference should instead be Section 4.2.6.
Yes
Data retention for R1 through R5 references the audit window, while for R6, it is based on a number of calendar years. We suggest that the data retention for R6 be made equivalent to that currently proposed for R1 through R5. AEP agrees overall with the proposed changes regarding data retention.
Yes
AEP believes the specified maintenance in Table 5 is partially duplicative of other control circuitry maintenance already required by PRC-005-2 in Table 1-5. Specifically, there are two components of circuitry; one from the fault pressure relay to the lockout relay and another from the lockout relay (auxiliary relay) to the interrupting devices. This is problematic since documenting maintenance on this circuitry might be recordable under either Sudden Pressure Relaying (Table 5) or under control circuitry maintenance (Table 1-5). AEP suggests including language in Table 1-5 to include control circuitry from the fault pressure relay to the lockout / auxiliary relay. The row associated with control circuitry testing in Table 5 would then be eliminated. The implementation plan does not address Requirement R6. AEP is fully supportive of the efforts of this drafting team, and the resulting draft standard. While we have chosen to vote in the affirmative on the latest draft, we remain concerned by potential difficulties posed by Table 5 in regards to proving compliance. AEP specifically encourages the drafting team to make the changes recommended in the first paragraph of our response to Q5.
Individual
AnthonyJablonski
ReliabilityFirst
Yes

Yes
ReliabilityFirst submits the following comments for consideration: 1. Requirement R3 – Requirement R3 sub-parts 3.1.1 and 3.1.2 are "OR" statements and should be bullet points to be consistent with the format of other NERC Reliability Standards. 2. Requirement R4 – Requirement R4 sub-parts 4.1.1 and 4.1.2 are "OR" statements and should be bullet points to be consistent with other NERC Reliability Standards.
Individual
Israel Beasley
Georgia Transmission Corporation
No
No
No
No
Yes
GTC is proposing to clarify the wording of the standard without changing what we believe is the intent of the Standard Drafting Team. We propose the following language: R3. Each Transmission Owner, Generator Owner, and Distribution Provider that utilizes time-based maintenance program(s) shall, except for components identified in R7, maintain its Protection System, Automatic Reclosing, and Sudden Pressure Relaying Components that are included within the time-based maintenance program in accordance with the minimum maintenance activities and maximum maintenance intervals prescribed within Tables 1-1 through 1-5, Table 2, Table 3, and Table 4-1 through 4-2, and Table 5. [Violation Risk Factor: High] [Time Horizon: Operations Planning] R4. Each Transmission Owner, Generator Owner, and Distribution Provider that utilizes performance-based maintenance program(s) in accordance with Requirement R2 shall, except for components identified in R7, implement and follow its PSMP for its Protection System, and Automatic Reclosing, and Sudden Pressure Relaying Components that are included within the performance-based program(s). [Violation Risk Factor: High] [Time Horizon: Operations Planning] R7. Following a notification under Requirement R6, each Transmission Owner, Generator Owner, and Distribution Provider shall determine its applicable newly-identified Automatic Reclosing Components as identified in Applicability section 4.2.6. R8. Each Transmission Owner, Generator Owner, and Distribution Provider that identified Automatic Reclosing Components per R7 shall: 8.1. Perform maintenance activities or provide documentation of prior maintenance activities according to either 8.1.1 or 8.1.2. 8.1.1. Complete the maintenance activities prescribed within Tables 4-1, 4-2(a), and 4-2(b) for the newly-identified Automatic Reclosing Component prior to the end of the third calendar year following the notification under Requirement R6; or 8.1.2. Provide documentation that the Automatic Reclosing Component was last maintained in accordance with the minimum maintenance activities and maximum maintenance intervals prescribed within Tables 4-1, 4-2(a), and 4-2(b).
Group
MRO NERC Standards Review Forum
Joe DePoorter
No
Yes
The proposed Standard speaks of Section 4.2.7 Applicability. But there is no Section 4.2.7 within the Standard. The Rational for R6 refers to Section 4.2.7, please clarify. The NSRF cannot accurately apply this section without knowing the Applicability of section 4.2.7. The NSRF does not see the reliability benefit of the BA passing along this information and questions if this should be a Requirement in the first place.
Yes

The NSRF does not understand why R6 has a retention requirement of of 3 calanedar years when R2-R5 has a “most recent” requirement? We do not see the “largest BES generator” changing multiple times every year. Please clarify.
No
No
Individual
Andrew Z. Pusztai
American Transmission Company, LLC
No
No
No
No
No
Individual
Heather Rosentrater
Avista
No
Yes
Under R6, the BA is required to notify the TOs, GOs and DPs within its balancing area of the largest generating unit in the balancing area on a yearly basis to determine what reclosing relays to maintain. The requirement fails to realize a GO may be in a BA but interconnect to the BES through another TOP. The reclosing relays affecting the GO may not be identified and maintained. We suggest the TOP be the entity to determine the reclosing relays to maintain based upon a threshold.
No
No
No
Individual
Andrew Gallo
City of Austin dba Austin Energy
Yes
City of Austin dba Austin Energy (AE) supports the comments of Florida Municipal Power Agency. Sudden Pressure Relaying (SPR) devices do not respond to electrical quantities and do not impact the reliable operation of the Bulk Electric System. Additionally, AE believes the addition of SPR to PRC-005 is administratively and operationally burdensome and unnecessary. AE already tests SPRs, but the record keeping is rolled into records for the autotransformer. Calling out SPRs in PRC-005 would require separate documentation for just one of many auxiliary devices on an autotransformer, creating an administrative burden which does not enhance the reliability of the BES. Further, these devices are located on top of the transformer and an outage will be required to gather necessary data, creating an operational burden.
Yes

AE supports the comments of Florida Municipal Power Agency and Sacramento Municipal Utility District.
Yes
AE supports the comments of Florida Municipal Power Agency.
Yes
AE supports the comments of Florida Municipal Power Agency.
Yes
AE supports the comments of Florida Municipal Power Agency.
Group
SERC Protection and Controls Subcommittee
David Greene
No
Yes
1) If the BA and this requirement is retained, please require the BA to also provide their basis (or means) of determining the gross MW or MVA capacity of the largest BES generating unit. For example, the BA could use gross capacity in MW or MVA derived from the FAC-008-3 rating, or the generator nameplate MVA, or the MOD-025-2 standard, or the Interconnection Agreement, or plant capacity as limited by the mechanical equipment (e.g., boiler, turbine, condenser). We prefer the BA use a means that is unlikely to vary from year-to-year, like generator nameplate MVA so that Automatic Reclosing at a given location is not oscillating into and out of Applicability. The TO / GO / DP need to know the BA’s basis in order to consistently determine the TO / GO /DP locations where the total installed capacity exceeds this largest unit's gross capacity size, and thus are within Automatic Reclosing Applicability. 2) The addition of the Balancing Authority to this Standard is problematic. This Standard focuses on the Maintenance and Testing of TO, GO, and DP assets: therefore, the responsibility to determine the assets that should be included in their program should be their responsibility. As such the requirement should be that the “TO, GO, and DP shall request …. “; not that the “BA shall notify …..”. Another option would be for this Requirement to be moved to a Standard that is applicable to the BA.
No
Yes
1) We concur with the Component definition change. Please add 'These are examples and were never intended to be an all inclusive list' at the end of the explanatory language now in the Supplementary Reference (clean) on pages 55 and 58 "The designation of what constitutes a control circuit component is very dependent upon how an entity performs and tracks the testing of the control circuitry. Some entities test their control circuits on a breaker basis whereas others test their circuitry on a local zone of protection basis. Thus, entities are allowed the latitude to designate their own definitions of control circuit components. Another example of where the entity has some discretion on determining what constitutes a single component is the voltage and current sensing devices, where the entity may choose either to designate a full three-phase set of such devices or a single device as a single component. These are examples and were never intended to be an all inclusive list."
Yes
In the Implementation Plan page 2 bottom, last bullet point, please add " or 'new to PRC-005' if the Component is newly included within PRC-005 scope" at the end of " Whether each component has last been maintained according to PRC-005-2 (or the combined successor standards PRC-005-3 and PRC-005-X), PRC-005-1b, PRC-008-0, PRC-011-0, PRC-017-0, or a combination thereof, or 'new to PRC-005' if the Component is newly included within PRC-005 scope." The comments expressed herein represent a consensus of the views of the above-named members of the SERC EC Protection and Control Subcommittee only and should not be construed as the position of SERC Reliability Corporation, its board, or its officers.
Individual
John Seelke

Public Service Enterprise Group
No
No
No
No
Yes
• With regard to R1, please clarify that an entity is NOT required to have a PSMP for all Section 4.2 Facilities. Its PSMP is only required for the Facilities listed in Section 4.2 that the entity owns. For example, a GO with no UFLS Protection Systems need not include these in its PSMP. • The maintenance of Sudden Pressure Relays in transformers will be most efficiently performed at the same time transformers are maintained. Their maintenance interval should therefore conform with transformer maintenance intervals, which greater than the 6 year interval in Table 5. We recommend 12 years. • The Implementation Plan for R3 addresses Automatic Reclosing relays in two places: o Paragraph #5 on p.7 for the 6 year interval o Paragraph #7 on p. 8 for the 12 year interval Since relays in the Applicability Section 4.2.6.1 and 4.2.6.2 cannot be identified until notification is made by the BA in R6, it appears that all 4.2.6.1 and 4.2.6.2 relays will be newly identified under R3.1.1 and would therefore have a three year implementation schedule. It would be preferable is R3.1.1 allowed a staggered implementation for newly identified relays as provided for in paragraphs 5 and 7. See the suggested language below for R3.1.1 3.1.1. Complete the maintenance activities prescribed within Tables 4-1, 4-2(a), and 4-2(b) for the newly-identified Automatic Reclosing Component following the notification under Requirement R6 in accordance to the table below; or Maintenance Interval % compliant after notification under R6 6 years 30% within 36 months; 60% within 60 months; 100% within 84 months 12 years 30% within 60 months; 60% within 108 months; 100% within 156 months
Individual
Chang Choi
City of Tacoma
Yes
Recognizing that even the technical report acknowledges that “[t]here is no operating experience in which misoperation of a pressure switch in response to a system disturbance has contributed to a cascading event,” it is a concern that an enforceable regulatory requirement to maintain sudden pressure relays will be established based upon a theoretical risk of inadvertant operation during a disturbance that might contribute to a cascading event. Consequently, unless evidence can be produced of actual inadvertant operation of sudden pressure relays protecting BES elements during a disturbance that, under slightly different system conditions, could have led to a cascading event (i.e., a “near miss”), modification of PRC-005-3 to address sudden pressure relays should not be necessary at this time. Setting aside the first comment submitted under Question 1, consider adding a footnote to the effect that this standard should not be construed to require an entity to apply Sudden Pressure Relaying [or Automatic Reclosing, except where integral to a Special Protection System]. This footnote would be especially important for 4.2.5.4 “Protection Systems and Sudden Pressure Relaying for station service or excitation transformers connected to the generator bus of generators which are part of the BES, that act to trip the generator either directly or via lockout or tripping auxiliary relays.” Setting aside the first comment submitted under Question 1, including “control circuitry associated with a fault pressure relay” in the proposed definition of Sudden Pressure Relaying, without modifying the definition of a Protection System, undermines prior assertions that this control circuitry is included in the definition of a Protection System or that Table 1-5 in PRC-005-2 and PRC-005-3 would apply to this control circuitry.
Yes
How does Requirement R6 address (a) Generator Owners whose generation may be part of a Pseudo Tie such that the generation is not electrically near the majority of the Balancing Authority’s

generation or (b) Transmission Owners or Distribution Providers who may interconnect with those Generator Owners but reside in a different Balancing Authority? Would the Transmission Operator, Transmission Planner, or Planning Coordinator be the more appropriate function to provide notification? Depending on the standards drafting team's response, it may also be necessary to modify the Applicability section. In any case, in order to avoid a potential compliance trap for entities registered only for functions (e.g., Balancing Authority) not normally associated with maintenance activities, it is strongly recommended that Requirement R6 be relocated to another standard as soon as possible so that PRC-005-X can remain applicable only to Transmission Owners, Generator Owners, and Distribution Providers.
Yes
Tacoma Power is generally supportive of the proposed change in data retention except for the following. First, Tacoma Power questions whether or not the Balancing Authority is the appropriate function related to Requirement R6 (see comment submitted under Question 2). Second, the statement that "…[f]or instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit…" may be construed to contradict the statement that "…the Transmisison Owner, Generator Owner, and Distribution Provider shall each keep documentation of…all performances of each distinct maintenance activity for the Protection System, Automatic Reclosing, or Sudden Pressure Relaying Component since the previous scheduled audit date…" Does the standards drafting team wish to modify the latter statement to something like the following? "…the Transmisison Owner, Generator Owner, and Distribution Provider shall each keep documentation of…all performances of each distinct maintenance activity for the Protection System, Automatic Reclosing, or Sudden Pressure Relaying Component since the previous scheduled audit date in addition to documentation of performance of at least one distinct maintenance activity for the Protection System, Automatic Reclosing, or Sudden Pressure Relaying Component prior to the previous scheduled audit date (except as permitted by the Implementation Plan)…"
Yes
Setting aside other concerns and questions, in the Supplementay Reference and FAQ Document, in the definition of Sudden Pressure Relaying, change "…that detecting…" to "…that detects…"
No
Individual
Jo-Anne Ross
Manitoba Hydro
Yes
R1.2: Since Table 5 does not include using monitoring to extend the maintenance intervals for Sudden Pressure Relaying, the references to Table 5 and Sudden pressure Relaying should be removed from this requirement. M1: For the same reason, the references to Sudden Pressure Relaying and Table 5 should be removed from the third paragraph of M1.
No
No
No
Yes
(1) Why are there two separate definition sections ("Definitions Used in this Standard" and "Definitions of Terms Used in Standard")? Is there something that differentiates these two sets of terms? (2) In the Implementation plan (page 11), consider revising to include "For Sudden Pressure Relaying Component" within section (9) instead of in the heading to clarify what is being referenced. It should read: "For Sudden Pressure Relaying Component maintenance activities with maximum allowable intervals of twelve (12) calendar years, as established in Table 5:"
Individual

Mauricio Guardado
Los Angeles Department of Water and Power
Yes
LADWP believes that it may not be necessary to add sudden pressure relays to PRC-005 for the reason that this devices are primarily for equipment health monitoring. Also, FERC did not specifically direct the inclusion of such devices to the scope of PRC-005.
Yes
LADWP is voting “Negative” on PRC-005-X for the reason that Requirement 6 (applicable to BAs)seems to be out-of-place in the standard, it does not align with the other requirements, and even in the provided rationale for the requirement, it is indicated that this requirement may be relocated to another standard during future reviews of standards for quality and content.
No
No
No
Individual
Si Truc PHAN
Hydro-Quebec TransEnergie
No
No
No
No
Yes
Hydro-Quebec TransEnergie (HQT) has an issue with the 6 calendar years of Maximum Maintenance Interval. We consider this interval too short because our Sudden Pressure Relays are Buchholz type relays. This type of relay is very reliable, therefore it is installed on the Free Breathing Transformers (FBT). HQT has only FBTs in its RTP (BES) network. A period of 6 years is too short for completing the testing and maintenance of all our equipment. HQT request to increase the Maximum Maintenance Interval to 12 calendar years for the Buchholz relay type.
Individual
Gul Khan
Oncor Electric Delivery LLC
No
Yes
Oncor recommends the following revised R6 language “Each Balancing Authority shall, at least once every calendar year with not more than 12 calendar months between notifications, notify each Transmission Owner, Generator Owner, and Distribution Provider within its Balancing Authority Area of the gross capacity, in MW or MVA, of the largest BES generating unit within the Balancing Authority Area.”
No
No
No

Group
SPP Standards Review Group
Robert Rhodes
Yes
Maintenance testing in Table 5 calls for testing the sensing mechanism once every 6 years and testing control circuitry to the trip coil of the interrupting device every 12 years. The SDT indicated that these intervals were consistent with other testing intervals in the existing standard. Yet we see a difference between these intervals and those contained in Table 1-5 which indicates control circuitry testing every 6 years. We also note that Table 3 indicates 12 year testing for control circuitry. We would appreciate any clarification the SDT could provide to indicate which intervals the Sudden Pressure Relay testing is consistent with. Insert 'and Sudden Pressure Relaying' between 'Systems' and 'for' in 4.2.5.3 in the Applicability section. Footnote 1 on Page 1 and the Rational Box for Requirement R6 refer to 4.2.7 in the Applicability section but there is no 4.2.7. The reference in the footnote is probably to 4.2.6. Insert an 'in' between 'requirement' and 'the' in the last line of the Rational Box for Requirement R6 on Page 8.
Yes
Rather than make the Balancing Authority soley accountable in Requirement R6, we suggest requiring the Balancing Authority provide the information within 30 days upon request from a Transmission Owner, Generator Owner or Distribution Provider. This places the burden of responsibility on the shoulders of those ultimately responsible for the Automatic Reclosing Relays and makes the Balancing Authority involvement secondary.
No
Yes
There is a reference to Applicability Section 4.2.7 in the Supplementary Reference document on Page 6 in the 2nd paragraph under Section 2.4 Applicable Relays. There is no 4.2.7 in the Applicability section. (See our comment in Question 1.) The reference should be to 4.2.6. In the newly inserted 3rd paragraph under Section 2.4 Applicable Relays on Page 6, the references to the Applicability section should be 4.2.1, 4.2.5.2, 4.2.5.3 (our recommendation in Question 1) and 4.2.5.4. Delete the reference to 4.2.6. Capitalize 'Fault' in the added section on Sudden Pressure Relays on Page 12. In the answer for 'Is Sudden Pressure Relaying installed on distribution transformers included in PRC-005-4?' on Page 12, change the reference from 4.2.6.1 to 4.2.5.4. In the question 'Are non-electrical sensing devices (other than fault pressure relays) such as as low oil level or high winding temperatures included in PRC-005-4?' on Page 12, delete the 2nd 'as'. In the answer to this question, insert a comma after 'December 2013'. In the continuation of this answer on Page 13, change 'fault pressure relay' to 'Sudden Pressure Relay'.
Yes
For consistency with other standards, most recently CIP-014-1, capitalize Part in the references in the VSLs for Requirement R1.
Group
ACES Standards Collaborators
Ben Engelby
No
The inclusion of sudden pressure relaying is consistent with the FERC directive.
Yes
We support NRECA's comments that the BA should be removed from PRC-005. The inclusion of the Balancing Authority as an applicable entity in this version of the draft standard and the associated addition of R6. We do not believe that the drafting team has provided sufficient technical justification to warrant the inclusion of Balancing Authorities as an applicable entity in a Protection System Maintenance standard and the inclusion of the associated R6 is onerous and meets the criteria to be classified as an "administrative" requirement. The applicable entities in this standard should only be those entities that own and maintain the Protection Systems described in the draft standard not an entity responsible "that integrates resource plans ahead of time, maintains load-interchange-

generation balance within a Balancing Authority Area, and supports Interconnection frequency in real time.”
Yes
As stated above, we disagree with the inclusion of the Balancing Authority to PRC-005. Therefore, we also disagree with the changes to the data retention relating to the BA. For Requirement R1, the data retention is reasonable, but the focus should be on the most current version of the program for audits. For Requirements R2-R5, there is improvement from maintaining the two most recent maintenance activities to the single most recent maintenance activity. However, we have an issue with maintaining evidence prior to the previous audit date and recommend removing the language, “whichever is longer.” This language could result in unintended consequences of maintaining evidence prior to when the standard is in effect.
Yes
We question the need to modify definitions and other parts of the standard that do not relate to sudden pressure relays. For example, why modify the word “component” to be a standard-specific term? The word component is used over 400 times in the NERC standards. Having a PRC-005 specific component type is very confusing. There are components relating to ACE, sub-components of requirements, components regulated by Nuclear Regulatory Commission, to name a few. Each of these occurrences of the word component are lower-cased, meaning that everyday dictionary definitions apply. By creating a PRC-005 “Component,” the drafting team has further complicated the reliability standards. We recommend striking the proposed definition.
Yes
Why has the drafting team decided to call this version PRC-005-X? The technical reference guide clearly states on page 5, “PRC-005-4 addresses this directive regarding sudden pressure relays and, when approved, will supersede PRC-005-3.” The use of the letter “x” as the version only adds confusion to industry members. Please use consistent naming conventions for the draft standards and their associated projects.
Individual
Joe Tarantino
Sacramento Municipal Utility District/Balancing Authority Northern California
No
Yes
SMUD encourages the SDT to adopt a 1500 MW threshold approach that is consistent with other NERC developed threshold applications as established in other standards/definitions for the following reasons: SMUD views the current Requirement R6 places an administrative burden on the BA requiring notification to FEs of the gross capacity of the largest BES generator unit that would be resolved through a threshold approach. An established threshold would also eliminate applicability adjustments when changes occur to the gross capacity of the largest BES generating unit within the BA footprint. SMUD also believes that the current requirements R3 & R6 places an onerous compliance burden on Functional Entities who reside in smaller BA footprints where larger generating units, typically included in the larger BA footprints, would exclude similar FEs who are located in their larger BAs. In addition to this issue SMUD believes the SDT’s current approach, where applicability of 4.2.6.1 is subject to ”installed gross generating plant capacity is greater than the gross capacity of the largest BES generating unit within the BA”, creates inconsistent applicability of automatic reclosing (relay) at generation plant substations.
No
No
No
Individual
David Jendras

Ameren
Yes
We agree with the SDT approach and commend the SPCS for its "Sudden Pressure Relays and Other Devices that Respond to Non-Electrical Quantities" in response to FERC order 758.
Yes
1) Ameren concurs with the SERC PCS comments and includes all of them via this reference. 2) Does R6 apply to an overall BA, like MISO; or the local BA, like Ameren? 3) We do not believe this requirement should be included in the standard because the rational for R6 references section 4.2.7 do not exist.
Yes
This is a good step in the right direction.
Yes
We agree with the SERC PCS response to this question.
Yes
1) We request the drafting team to use this as an opportunity to better clarify Automatic Reclosing control circuitry. In previous drafts we have specifically asked for ANSI device numbers in the Supplementary Reference during PRC-005-3 development and the SDT had elected not to. The SPCS "Sudden Pressure Relays and Other Devices that Respond to Non-Electrical Quantities" Appendix C categorizes devices 25 and 79 as 'Subject of separate report by SAMS and SPCS' which implies both these devices could be within Automatic Reclosing scope. Since the 79 is the reclosing relay itself, this implies the 25 could be part of the Control Circuitry. We suggest another FAQ: "What ANSI Device numbers, if any, do the Automatic Reclosing Component Types include? Answer: a) The ‘Reclosing relay’ Component Type includes ANSI device 79, which could be a stand-alone relay if electromechanical; or could be the 79 function within a microprocessor-based relay. b) The ‘Control circuitry associated with the reclosing relay’ Component Type could include ANSI device 25 as part of the circuitry but it's important to focus on the concern being addressed within the standard which is premature autoreclosing that has the potential to cause generating unit or plant instability. The device 25 would need to be included in your maintenance only if device 25 could lead to such premature autoreclosing." Our purpose in seeking this clarification is for entities to comply as they implement rather than later be trapped into a non-compliance later.
Group
Bureau of Reclamation
Erika Doot
Yes
The Bureau of Reclamation (Reclamation) does not support the proposal to include sudden pressure relays to PRC-005. Reclamation does not agree with the System Protection and Control Subcommittee’s Technical Report classification that sudden pressure relays are designed to “initiate actions to clear faults or mitigate abnormal system conditions to support reliable operation of the Bulk Power System.” Instead, Reclamation believes that sudden pressure relays “initiate action for abnormal equipment conditions” to protect transformers (like thermal relays and pressure switches, etc.). Sudden pressure relays are designed to prevent further equipment damage when a transformer experiences an internal fault, not to protect the system or respond to external faults. Therefore, Reclamation believes that sudden pressure relays fall within the classification of devices that NERC has not proposed to include within PRC-005. Reclamation’s position is consistent with several industry documents, including the 1991 WECC Report, Transformer Protection Sudden Pressure Relays, http://www.wecc.biz/library/Documentation%20Categorization%20Files/Reports%20and%20Whitepapers/Transformer%20Protection%20Sudden%20Pressure%20Relays.pdf As described in the WECC report, some types of sudden pressure relays may misoperate due to through-fault current. If NERC’s intent is to prevent the misoperation of sudden pressure relays due to through-fault current from external system faults, Reclamation does not believe that PRC-005 is the appropriate standard to address the issue. Reclamation believes that the issue is better addressed through PRC-004 misoperations analysis and industry technical guidance documents (e.g., on blocking schemes to prevent sudden pressure relay misoperations due to external faults).
No

No
No
Yes
Reclamation requests that drafting teams post comments received on the Standards Authorization Request (SAR) to promote transparency, and prepare dispositions of comments on these documents. The industry invests substantial resources in the formulation of comments and would appreciate feedback on comments submitted.
Group
ISO RTO Council Standards Review Committee
Greg Campoli
Yes
We understand the need for NERC to address the FERC directive for adding Sudden Pressure Relays into the System Protective Device Maintenance requirements. As the drafting team acknowledges in the draft, these devices are not consistent with the current NERC term for Protection System. We think adding these devices into this standard will result in confusion in the future that any protective devices and mechanical actuators may be added to PRC-005 regardless of whether it is a part of the Protection System. The rationale for adding Sudden Pressure should be memorialized in the standard itself and not just in the change history so future drafting teams understand the circumstances leading to the addition.
Yes
We do not support R6 as a reliability requirement. We believe the intent of the BA communicating any changes of the largest BES generating unit to the Transmission Owner, Generator Owner, and Distribution Provider within its Balancing Authority Area is to assist them in determining if any of their auto reclosing schemes meet the applicability criteria for inclusion in their maintenance program. This imposes a compliance requirement on entities which is unnecessary for reliability. All registered entities are obligated to provide data to NERC through Rules of Procedure Section 1600. Alternatively, the identification of the largest BES generating unit within a BA can easily be obtained through GADS by amending the GADS reporting procedures to include a BA association. We disagree with the need to make the provision of information, especially one that rarely changes, through a NERC standard. Requiring the BA to report this information is inconsistent with the provision of numerous other data registered entities are required to provide through other means. NERC can create and make available a list of the largest BES generating units by BA to achieve the same intent.
No
No
Yes
R3.1. Adding the word “notified” after the word “each” could add some clarity. As written it could read to mean that “all TOs, GOs and DPs would be required to do maintenance for the same relay given that the BA informed them of the largest unit (per R6); which would seem to itself include all TOs, GOs and DPs. The addition is somewhat redundant but it may not hurt to add the adjective.
Individual
Jamison Cawley
Nebraska Public Power District
Yes
Did the survey respondents indicate if the testing of the transformer sudden pressure device and associated protective circuitry corresponded to normally scheduled transformer maintenance intervals? One of the unintended consequences of testing the sudden pressure device is increasing the number of times a transformer is taken out of service for maintenance. Taking the transformer out of service for another maintenance activity will increase the unavailability of the device, reducing

system reliability. It would be beneficial that the testing interval specified for sudden pressure relays be flexible enough that the pressure relay test frequency could equal the transformer test frequency (SFRA, Doble, TTR, etc.). Also, we are unaware of instances of Sudden Pressure Relay devices creating instability, uncontrolled separation, or a cascading event. Has there been an instance where the failure of a Sudden Pressure Relay can be shown as a contributing factor in any case of instability, uncontrolled separation, or cascading event?
No
No
Yes
This is in regard to the last sentence in the response to the question, "Why is the maintenance of Sudden Pressure Relaying being addressed in PRC-005-4?" in Section 2.4.1 of the Supplementary Reference and FAQ Document. The response indicates that the operation of Sudden Pressure Relaying can limit damage to equipment. In the event of an internal fault releasing sufficient energy to actuate the Sudden Pressure Relay, the equipment will have already been damaged. We feel this part of the response may be misleading.
No
Individual
Karen Webb
City of Tallahassee
Yes
The City of Tallahassee (TAL) believes Sudden Pressure Relaying should not be added to PRC-005-X because they are not necessary for the "reliable operation" of the bulk power system as defined in statute. What is necessary for the reliable operation of the BPS are differential relays, overcurrent relays, etc., that are there to clear a major phase to ground or phase to phase fault that if left uncleared can cause instability. The purpose for a sudden pressure relay is primarily to monitor equipment health, e.g., detecting a turn-to-turn failure, not a phase to ground or phase to phase fault. If a sudden pressure relay fails to operate, there is no threat to BPS reliability since the differential relay / overcurrent relays are there if the fault develops into a major phase to ground or phase to phase fault. TAL believes that the use of sudden pressure relays are a good business practice, but we also believe that utilities should be free to adopt good business practice beyond the requirements of the standards, without the reverse incentives that being regulated, audited, etc., bring.
Yes
As proposed, this language will not impact TAL. However, smaller utilities coordinating with multiple BAs will now be required to coordinate and document heavily on something that adds little value to the reliability of the BES. It does not appear to add value to the standard. A requirement for a BAL should not be buried in a PRC standard.
Yes
The change in data retention should not impact TAL. However, as commented for question 2, the burden on smaller utilities will increase.
No
Group
Dominion
Mike Garton
No
Yes

No
No
No
Group
Duke Energy
Colby Bellville
No
No
No
No
Yes
Duke Energy requests clarification from the drafting team on the responsibilities of an entity in the event that the entity decides to block or remove a Sudden Pressure Relay device from service after the standard has taken effect. As written, the draft standard does not provide any requirement as to the documentation or retention of records regarding Sudden Pressure Relays that have been blocked or taken out of service. Will an entity be required to notify the ERO or a Regional Entity of the decision to remove a device, or retain documentation on the device after its removal? Also, we request clarification from the drafting team regarding the draft standard's title, PRC-005-X. Upon the conclusion of this project as well as Project 2014-01 (Standards Applicability for Dispersed Generation), will this standard be renamed PRC-005-4, or remain as PRC-005-X? The changing of the name of the standard will require alteration of an entity's internal documentation, and we would like to be aware of any possible impending changes.
Group
National Grid
Michael Jones
Yes
We suggest revising section 4.2.1 to read as: "Protection Systems and Sudden Pressure Relaying installed for the purpose of detecting Faults and initiating the automatic operation of interrupting device(s) to isolate the BES Elements it is monitoring." Section 4.2.1 should only apply to detecting devices required to initiate fault clearing action.
Individual
Bill Fowler
City of Tallahassee
Yes
The City of Tallahassee (TAL) believes Sudden Pressure Relaying should not be added to PRC-005-X because they are not necessary for the "reliable operation" of the bulk power system as defined in statute. What is necessary for the reliable operation of the BPS are differential relays, overcurrent relays, etc., that are there to clear a major phase to ground or phase to phase fault that if left uncleared can cause instability. The purpose for a sudden pressure relay is primarily to monitor equipment health, e.g., detecting a turn-to-turn failure, not a phase to ground or phase to phase

fault. If a sudden pressure relay fails to operate, there is no threat to BPS reliability since the differential relay / overcurrent relays are there if the fault develops into a major phase to ground or phase to phase fault. TAL believes that the use of sudden pressure relays are a good business practice, but we also believe that utilities should be free to adopt good business practice beyond the requirements of the standards, without the reverse incentives that being regulated, audited, etc., bring.
Yes
As proposed, this language will not impact TAL. However, smaller utilities coordinating with multiple BAs will now be required to coordinate and document heavily on something that adds little value to the reliability of the BES. It does not appear to add value to the standard. A requirement for a BAL should not be buried in a PRC standard.
Yes
The change in data retention should not impact TAL. However, as commented for question 2, the burden on smaller utilities will increase
No
No
Individual
Karin Schweitzer
Texas Reliability Entity
Yes
Section 4: Applicability – 4.2.4 should have Sudden Pressure Relaying (SPR) added to its inclusion as a SPS. While not often used as an SPS, the SPR needs to be included here to allow the inclusion of SPR when it is part of a Registered Entity's (RE) SPS. We recognize that the original intent was only to include Sudden Pressure Relaying whose purpose is to detect faults. Adding "and Sudden Pressure Relaying" after "Protection Systems" but before the words "installed as a Special Protection System…" will eliminate a reliability gap where SPR isn't otherwise included in the PRC-005 when it is part of an SPS. 4.2.5.3 should include SPR for those transformers included in this section. Transformers with PRC-005 included Protection Systems (PE) should also have their SPR covered by PRC-005. We recognize that the original intent was only to include Sudden Pressure Relaying whose purpose is to detect faults. Adding "and Sudden Pressure Relaying" after "Protection Systems" but before the words "for transformers connecting aggregated generation…" will eliminate a reliability gap otherwise left in transformer protection for transformers covered by PRC-005. Section 6: Definitions Used in this Standard – "Sudden Pressure Relaying" definition - After "isolate" in the phrase "to isolate the equipment" add "at least". This addition will allow the SPR system to include the other equipment that the SPR does clear. This will prevent the SPR definition from being limited to only systems that isolate only the monitored equipment. "Fault pressure relay" within the "Sudden Pressure Relaying" definition, the description is for a singular "device". By adding ", or combination of devices," after "device" the singular meaning is expanded. A Fault pressure relay need not be defined in terms of a single component but may be inclusive of a system of devices that perform the detection of the rapid change in pressure. If this change isn't made the fault pressure relay systems consisting of more than one component may not be covered by PRC-005, resulting in a reliability gap. "Countable Event" definition excludes "relay settings different from specified settings". Doing so may result in a reliability gap as that represents one of the largest populations for misoperations. Maintenance can include settings adjustment and a PSMP could include a field check of the settings. Table 1-5 "Component Type - Control Circuitry Associated With Protective Functions" should expressly include or exclude Sudden Pressure Relaying control circuitry. Without that clarification there may be confusion in the auditing and enforcement of PRC-005. Table 2 "Alarming Paths and Monitoring" should expressly include or exclude Sudden Pressure Relaying control circuitry. Without that clarification there may be confusion in the auditing and enforcement of PRC-005.
No
Yes

Page 10, 3rd paragraph, last sentence should include “Automatic Reclosing and Sudden Pressure Relaying” after “Protection System” but before “Component Type”. This change will be consistent with language in the last sentence of the following paragraph.
No
Yes
Footnote on page 4 – the references are incorrectly adjusted and should remain as 4.2.6.1 and 4.2.6.2. Rationale for R6 (page 8) - the reference is incorrectly adjusted and should remain as 4.2.6.
Individual
Richard Vine
California ISO
Individual
Sergio Banuelos
Tri-State Generation and Transmission Association, Inc.
No
No
Yes
Tri-State supports the change to require only retaining the most recent performance of maintenance activity.
No
Yes
Tri-State disagrees with the 6 year interval and believes it should be a 10 year interval to align with transformer maintenance. We don't believe that the failure modes of SPRs are the same as other EM relays.
Group
Florida Municipal Power Agency
Frank Gaffney
Yes
There has been some misinformation floating in industry as to whether FERC directed inclusion of sudden pressure relays in PRC-005. In Order 758, that they did not. The NOPR did propose to require it, e.g., Order 758 at P 12: “In the NOPR, the Commission noted a concern that the proposed interpretation may not include all components that serve in some protective capacity. The Commission’s concerns included the proposed interpretation’s exclusion of auxiliary and non-electrical sensing relays. The Commission proposed to direct NERC to develop a modification to the Reliability Standard to include any component or device that is designed to detect defective lines or apparatuses or other power system conditions of an abnormal or dangerous nature, including devices designed to sense or take action against any abnormal system condition that will affect reliable operation, and to initiate appropriate control circuit actions.” Many entities commented on this, including NERC. In its comments, NERC proposed to develop (Order 758 P 14) “technical documents (that) will address those protective relays that are NECESSARY FOR THE RELIABLE OPERATION OF THE BULK-POWER SYSTEM and will allow for differentiation between protective relays that detect faults from other devices that monitor the health of the individual equipment and are advisory in nature (e.g., oil temperature)” (emphasis added). And, depending on the results of the technical papers, NERC stated that it would (Order 758 P 14) “propose a new or revised standard (e.g. PRC-005) using the NERC Reliability Standards development process to include maintenance of such devices, including establishment of minimum maintenance activities and maximum maintenance intervals.” FERC does not direct the inclusion of sudden pressure relays, instead (Order 758, P 15): “The Commission accepts NERC’s proposal, and directs NERC to file, within sixty days of publication of this Final Rule, a schedule for informational purposes regarding the development of the technical documents referenced above, including the identification of devices

that are designed to sense or take action against any abnormal system condition that will affect reliable operation. NERC shall include in the informational filing a schedule for the development of the changes to the standard that NERC stated it would propose as a result of the above-referenced documents. NERC should update its schedule when it files its annual work plan." Subsequent to the Order, the NERC Planning Committee approved a report of the NERC System Protection and Control Subcommittee that recommends inclusion of sudden pressure relays in PRC-005. FMPA disagrees with the conclusion of the NERC SPCS. Section 215 defines the bulk-power system as including (at (a)(1)(A)): "…control systems NECESSARY for operating an interconnected electric energy transmission network …" (emphasis added). In addition, NERC's proposal is to evaluate what non-electrical relays are: "… NECESSARY for the RELIABLE OPERATION of the Bulk-Power System …" (emphases added, Order 758 P 14). The statute defines "reliable operation" of the bulk-power system as (at (a)(4)): "The term `reliable operation' means operating the elements of the bulk-power system within equipment and electric system thermal, voltage, and stability limits so that instability, uncontrolled separation, or cascading failures of such system will not occur as a result of a sudden disturbance, including a cybersecurity incident, or unanticipated failure of system elements". Sudden pressure relays do none of this; that is, the purpose of sudden pressure relays is not to operate equipment within thermal, voltage and stability limits so that instability, uncontrolled separation or cascading will not occur. Sudden pressure relays are not "necessary", in fact, older transformers will likely not have them. What is necessary for "reliable operation" are the differential relays, overcurrent relays, etc., that are there to clear a major phase to phase or phase to ground fault that if left uncleared can cause instability. A sudden pressure relay is there primarily for equipment health monitoring, e.g., detecting a turn-to-turn failure, not a phase to ground or phase to phase fault. If a sudden pressure relay fails to operate, there is no threat to BPS reliability since the differential relay / overcurrent relays are there if the fault develops into a major phase to ground or phase to phase fault. Hence, FMPA is voting negative and recommends a reversal of the SCPS recommendation. It is beyond the scope of the statute, not necessary for bulk-power system reliability, and more importantly, will result in unintended consequences due to perverse incentives that may cause entities to disable their sudden pressure relays, put them on alarm only, etc. We need to resist the perception that all good utility practice needs to be regulated by standard, that is not the intent of the statute. The statute is written that only those necessary to prevent blackouts should be regulated by standard. Utilities should be free to adopt good business practice beyond the requirements of the standards, like sudden pressure relays and testing of those relays, without the reverse incentives that being regulated, audited, etc., bring.
Yes
FMPA believes the SDT has done a good job in concept around the inclusion of reclosing relays; however, the BA is not always the "right" entity to identify the largest loss of source contingency. There are numerous very small BAs, some of whom do not even have any BES generation within their BA Area. In those cases, those small BAs usually participate in a Reserve Sharing Group (RSG). As such, FMPA recommends one of three approaches: 1) establish a brightline as SMUD proposes, e.g., 1500 MW; 2) make the requirement applicable to the Reliability Coordinator instead of the BA; or 3) word the requirement such that if a BA participates in a Reserve Sharing Group, the BA can identify the largest loss of source in the Reserve Sharing Group rather than its own BA Area in a similar fashion to BAL-002.
Individual
Scott Langston
City of Tallahassee
Yes
The City of Tallahassee (TAL) believes Sudden Pressure Relaying should not be added to PRC-005-X because they are not necessary for the "reliable operation" of the bulk power system as defined in statute. What is necessary for the reliable operation of the BPS are differential relays, overcurrent relays, etc., that are there to clear a major phase to ground or phase to phase fault that if left uncleared can cause instability. The purpose for a sudden pressure relay is primarily to monitor equipment health, e.g., detecting a turn-to-turn failure, not a phase to ground or phase to phase

fault. If a sudden pressure relay fails to operate, there is no threat to BPS reliability since the differential relay / overcurrent relays are there if the fault develops into a major phase to ground or phase to phase fault. TAL believes that the use of sudden pressure relays are a good business practice, but we also believe that utilities should be free to adopt good business practice beyond the requirements of the standards, without the reverse incentives that being regulated, audited, etc., bring.
Yes
As proposed, this language will not impact TAL. However, smaller utilities coordinating with multiple BAs will now be required to coordinate and document heavily on something that adds little value to the reliability of the BES. It does not appear to add value to the standard. A requirement for a BAL should not be buried in a PRC standard.
Yes
The change in data retention should not impact TAL. However, as commented for question 2, the burden on smaller utilities will increase.
No
Group
JEA
Tom McElhinney
Yes
NERC needs to get clarification from FERC. Because the order states any sensing systems that monitor the health of any component of the BES, this could lead to major scope creep. The next version will be “Protection Systems, Automatic Reclosing, Sudden Pressure Relaying, Vibration Monitoring, Fuel Pumps, Flame out Sensors, Temperature Monitoring, etc., etc., etc.
Individual
Dixie Wells
Lower Colorado River Authority
Yes
FERC Order 758 did not direct inclusion of sudden pressure relays, these relay types are for equipment health not BES security.
Yes
Propose inclusion of a 1500 MW bright-line for reclosing relays to remove administrative burden on BA, effectively removes the BA from the applicability (R6).
No
No
No
Individual
Bob Thomas
Illinois Municipal Electric Agency
Group
Seattle City Light
Paul Haase

Yes
Seattle City Light supports the general concept of testing for some (but not all) sudden pressure relays, and believes the Standard Drafting Team to have done a good job in identifying and specifying in the draft Standard only those sudden pressure relays required by BES reliability. Seattle would not support the expansion to testing to sudden pressure relays not in scope of the present draft PRC-005-X, and wishes to express concern about the recent trend of enlarged scope throughout the body of Standards. The ongoing scope creep does not appear consistent with either the recommendations of the Expert Review Panel (to focus effort on revising existing Standards to be more clear) or with NERC's concept of a steady-state body of world-class Standards (which would require boundaries to be set and new requirements to be thoroughly validated before being proposed).
Yes
Seattle City Light supports the comments of FPMA as regards the addition of Balancing Authority to PRC-005-X. Specifically: FMPA believes the SDT has done a good job in concept around the inclusion of reclosing relays; however, the BA is not always the “right” entity to identify the largest loss of source contingency. There are numerous very small BAs, some of whom do not even have any BES generation within their BA Area. In those cases, those small BAs usually participate in a Reserve Sharing Group (RSG). As such, FMPA recommends one of three approaches: 1) establish a brightline as SMUD proposes, e.g., 1500 MW; 2) make the requirement applicable to the Reliability Coordinator instead of the BA; or 3) word the requirement such that if a BA participates in a Reserve Sharing Group, the BA can identify the largest loss of source in the Reserve Sharing Group rather than its own BA Area in a similar fashion to BAL-002. Seattle adds that the concern about small BAs is not small. Within WECC (which hosts one third of all NERC BAs), more than half of BAs could be considered "small" BAs having limited information/influence regarding largest contengincies. Perhaps one third of BAs continent-wide could fall into this same category.
Yes
Seattle City Light believes the drafting team has made appropriate and welcome clarifications to the data retention period in PRC-005-X. However Seattle remains concerned that auditors may interpret the clarifications variously, given that they differ from PRC-005 auditing practices to date. As such, Seattle recommends that something akin to a CAN be issued in this case, to clearly state the clarifications for both registered entities and auditors alike.
Yes
Seattle City Light appreciates the effort to updat the supplemental documents to include information about sudden pressure relays prior to the ballot on PRC-005-X. Seattle would have prefered a stand-alone document on sudden pressure relays, rather than spreading the new information throughout two existing (and large) documents. Seattle also wonders where from the "frequently asked questions" were sourced, given that the draft Standard has not been posted for many weeks.
Yes
Seattle City Light seeks clarification and/or justification of the requirement to test the function of sudden pressure relay actuators. Access to such actuators within oil tanks can be difficult, and it is not certain that the risk of oil contamination, components being dropped into tanks, or other practical problems associated with testing is less than the reliability benefit of testing such actuators. Seattle wonders if alternative approaches to actuator testing might be accepted and what they might be.
Individual
Roger Dufresne
Hydro-Quebec Production
Individual
Wiliam Waudby
Consumers Energy Company
Yes
Applicability 4.2.5.3 Because transformers used to aggregate generation are listed separately, they should also have sudden pressure relays included. The aggregation could include more than dispersed generation, for example a group of 19MVA gas peakers on one site. Therefor the

beginning of the first sentence should read “Protection Systems and Sudden Pressure Relaying for transformers…”. The recent draft of the dispersed generation white paper included the transformer that aggregates the generation as a BES Element, therefore the SPR should be applied to transformers functioning to aggregate generation over 75MVA. 6 Definitions Used in this Standard. The definitions section should include a definition for “control circuitry”. Investigations into the failure of BES equipment to operate in the desired sequence has, on occasion, identified permissive contacts failing to function correctly, causing a misoperation. A definition of the control circuitry and an associated requirement as to maintenance testing requirements would clarify the extent of maintenance required and should result in a more reliable BES. 6 Definitions Used in this Standard. We agree that the previous definition of “Component” was explanatory and not appropriate, however the replacement definition is weak to the point of being useless. Relying on the Supplementary Reference and FAQ Documents to address a definition is not appropriate, given the inclusion of other definitions within this standard. The following definition for Component is suggested “Any specific element of a Protection System, Automatic Reclosing or Sudden Pressure Relaying including, but not limited to protective relays, communication system, voltage and current sensing devices, protection system dc supply system, trip coils or actuators of interrupting devices, reclosing relays, sudden pressure relay, gas accumulation relay, electromechanical lockout and/or tripping auxiliary devices and battery charger.” 6 Definitions Used in this Standard. The purpose of a maintenance standard should be to determine if equipment is operating in the intended manner. The definition for Countable Event correctly excludes misoperations, which seems fair. However by listing items such as “relay settings different from specified settings” as a misoperation, the standard has a conflict with the maintenance activity in the tables. Specifically the first maintenance activity on Table 1-1, page 19 is to “verify that the settings are as specified”. While there may not have been an actual misoperation, this exclusion may be interpreted to mean that finding the settings not as specified is not a Countable Event, which from the table it should be. An incorrect relay setting could result in a risk to the reliability of the BES just as much as a defective relay. An Entity may have systemic problems leading to misoperations that would be masked by not including these items in its performance based maintenance program. We recommend that the SDT review the listing of exclusions in Countable Events and verify that they do not conflict with the maintenance activities of the tables. Table 1-1, page 19. A maintenance activity for all relays is to verify the “as found” settings. Since it is possible that a microprocessor relay could be left without the appropriate protective functions enabled, it would seem prudent to verify the “as left” settings of the microprocessor relay. This is appropriate because most microprocessor relays have multiple setting groups and the testing may be conducted by modifying the setting group or by changing to an alternate group. We suggest that the last step in the maintenance activity for microprocessor relays is to verify the correct group is enabled and its “as left” settings are correct. Measure M1. One aspect of Measure M1 addresses monitoring to extend the maintenance intervals. Table 5 for Sudden Pressure Relaying (correctly) does not include monitoring. The wording addition of “…and Sudden Pressure Relaying” to the third paragraph of M1 should be deleted, since (per Table 5) it does not apply. Rational for R6. The rational mentions Section 4.2.7 Applicability, however there is no such section in this Standard. Section 4.2.6 is probably the intended reference. R6. The determination of critical reclosing locations (and the documentation requirements) should reside within a planning standard, not in PRC-005. Once the facility locations are established, the maintenance of the devices at those locations should fall to PRC-005. The inclusion of the Balancing Authority and Requirement R6 should be removed from PRC-005.
No
No
No
No
Individual
Angela P Gaines
Portland General Electric Company

Yes
Portland General Electric Company (PGE) appreciates the work of the standard drafting team and its efforts to craft a workable standard. However, PGE has concerns based on the following comment from the Supplementary Reference and FAQ document, (page 3, section 2.3): ...if the Element is a BES Element, then the Protection System protecting that Element should then be included within this standard. Although this version of the proposed standard addresses sudden pressure relays, the above comment suggests a much broader increase in protection system testing and maintenance. The scope of testing and documentation suggested by the comment above creates an unreasonable burden that would not produce a commensurate increase in reliability to the BES. In fact, the extensive testing suggested by this language could very well decrease reliability because all testing carries with it a level of risk. PGE suggests that by defining specific elements for the term Protection System, per the NERC definitions of terms, maintenance efforts are focused on the areas of greatest benefit while providing entities with some assurance that the maintenance burden has a well defined limit. PGE also has specific concerns regarding the testing of the sensing mechanism of sudden pressure relays. Testing of SPR sudden pressure relays requires increasing tank pressure on gas space devices then opening a plug to create a sudden pressure drop. Devices of the oil pressure FPR type would require an external pressure pump to simulate a change in pressure. To perform these tests, utilities would need to remove the protected transformer from service, reducing reliability of the BES. In addition to taking transformers out of service, utilities would need to physically remove Buckholtz relays from the transformers in order to test rapid oil flow sensing. The added complexity of testing Buckholtz relays would increase the down time of critical transformers and introduce the possibility that the relays are not reinstalled properly.
No
No
Yes
Please see my comments in question 1.
No
Individual
RoLynda Shumpert
South Carolina Electric and Gas
Group
Florida Power & Light
Mike O'Neil
No
Yes
Specific to R6, in some regions, this information is already available to all Transmission Owners, Generator Owners, and Distribution Providers. A list of all generating facilities with the location, Gross & Net MW for each BA, including the largest units, is provided annually to the Region (FRCC). There is no need to provide this information to entities when it’s already available. R6 should be changed to provide the information if it isn't available by the Region.
No
No
No
Group

Southern Company: Southern Company Services, Inc.; Alabama Power Company; Georgia Power Company; Gulf Power Company; Mississippi Power Company; Southern Company Generation; Southern Company Generation and Energy Marketing
Wayne Johnson
No
Yes
We do not disagree that there needs to be some way for the Enitity to get the information from the BAs; however, the requirement as stated belongs in an existing or new Standard which is applicable to the BA. If the requirement remains in Prc-005-x, it should read as follows: “TO, GO, and DP shall request …. “; not that the “BA shall notify …..” since this Standard is specifically focused on the M&T activities related to TO, GO, and DP Protrction Systems. Additionally the verbiage used in the Standard “notify each Transmission Owner, Generator Owner, and Distribution Provider within its Balancing Authority Area..” should be changed to “notify each Entity (TO, GO, DP) within its Balancing Authority Area …” to avoid the misinterpretation that it is all TOs and GOs; but only DPs within the BA area.)
No
No
No
Group
Associated Electric Cooperative, Inc. - JRO00088
David Dockery
Yes
AECI supports FMPA’s comments. - - - Suggestion - - - FOR: PRC-005-X, Applicability 4.2.1 REMOVE: “and Sudden Pressure Relaying” APPEND: “,and Sudden Pressure Relaying configured on transformers to support reliable operation of the Bulk-Power System.” RATIONALE: Accuracy - The “SPCS Order 758 Sudden Pressure Report Final 02132014.pdf”, page 9, Table 1, Column 1, “Sudden Pressure (63)”, (conditional), failed to include the same qualifying phrase “to support reliable operation of the Bulk-Power System” (located: Appendix D, “Pressure Switch (63), “Conclusion:”, final sentence) for the type of fault clearing that pertains. AECI believes this omission misled the PRC-005-X SDT to overgeneralize that all transformer Sudden Pressure Relay implementations should be applicable, rather than the much more restricted subset specified within the referenced report’s Appendix D Details.
Yes
AECI supports FMPA’s comments. Further, AECI emphasize FMPA’s assertion of the technical inequity within the current draft. - - - Suggestions - - - FOR: PRC-005-X, Applicability 4.2.6.1 REPLACE: “the gross capacity of the largest BES generating unit within the Balancing Authority Area” WITH: “1500 MW” RATIONALE: Consistency of this bright-line threshold for plants within other NERC Standards. - - - OR - - - FOR: PRC-005-X, Applicability 4.2.6.1 REPLACE: “Balancing Authority Area” WITH: “Balancing Authority Area or the Balancing Authority’s Reserve Sharing Group” RATIONALE: The NERC Glossary of Terms definition for “Reserve Sharing Group”, embodies the concept of the Areas of the RSG’s BAs.
No
Yes
See RATIONALE: AECI submitted for any suggested changes the SDT might adopt.
No
Group
MEAG Power

Scott Miller
Group
Bonneville Power Administration
Andrea Jessup
Yes
BPA suggest clarification as to which devices would fall under the classification of Sudden Pressure Relaying. The sudden pressure device is a specific relay that senses pressure waves inside the transformer main tank. However, the definition given on page 5 (red-line version) indicates that Sudden Pressure Relaying includes devices which monitor sudden oil flow. Both the buchholz relay and the load tap changer protective device monitor a sudden flow and are different devices than the sudden pressure relay. Are those devices included under this standard?
No
No
No
BPA noted that PRC-005 Attachment A "Criteria for a Performance-Based Protection System Maintenance Program" contains the method to continue the use of a performance-based system which is different than the time based system proposed under this standard. The supplementary reference and FAQ document provide examples of how to establish performance based maintenance systems. When performance based maintenance practices can be practiced they provide value to the utility. Does the standard intend to use a similar approach or concepts from a streamlined reliability centered maintenance program when establishing time based maintenance intervals for sudden pressure relaying?

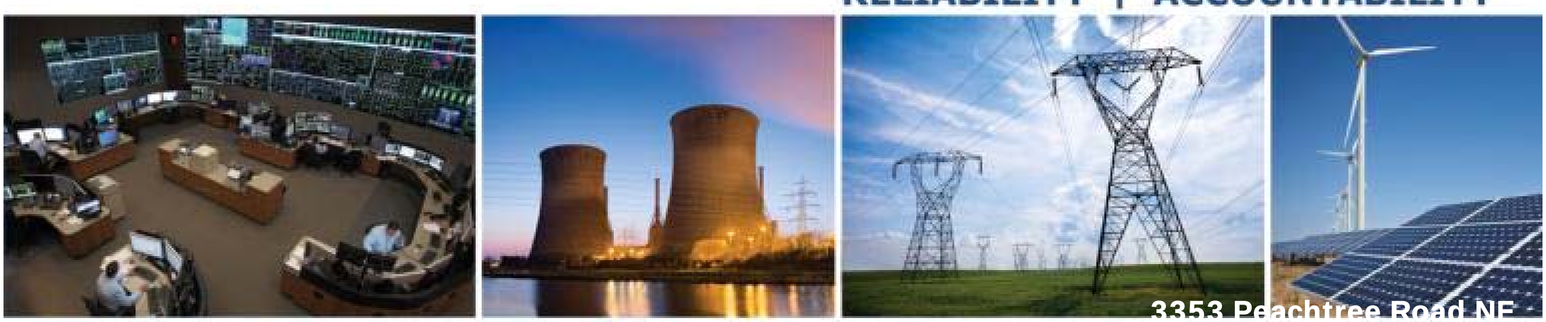
NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Consideration of Comments Summary

Project 2007-17.3 Protection System Maintenance and Testing

July 30, 2014

RELIABILITY | ACCOUNTABILITY



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Introduction

The Project 2007-17.3 drafting team thanks everyone who submitted comments on the draft PRC-005-X standard. This standard was posted for a 45-day public comment period from April 17, 2014, through June 3, 2014. The ballot was extended by one day to achieve quorum. NERC asked Stakeholders to provide feedback on the standard and associated documents through a special electronic comment form. There were 56 sets of responses, including comments from approximately 166 people from approximately 117 companies, representing all 10 Industry Segments.

All comments submitted may be reviewed in their original format on the standard's [project page](#).

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

Purpose

The Protection System and Maintenance Testing (PSMT) standards drafting team (SDT) appreciates industry's comments on the PRC-005-X standard. The SDT reviewed all comments carefully and made changes to the standard accordingly; however, the new Standards Process Manual (SPM) does not require the SDT to respond to each comment if a successive ballot is needed. The following pages are a summary of the comments received and how the PSMT SDT addressed them. If a specific comment was not addressed in the summary of comments, please contact the NERC standards developer or one of the SDT members to discuss.

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

Sudden Pressure Relay Directive

One commenter with several supporters stated that "[t]here has been some misinformation floating in industry as to whether FERC directed inclusion of sudden pressure relays in PRC-005." Other commenters asserted that sudden pressure relays do not impact the reliable operation of the Bulk Electric System; therefore, should not be included in PRC-005. Below is additional background regarding the FERC directive and why Sudden Pressure Relays are being added to PRC-005-X.

FERC NOPR Proposing to Approve PRC-005 Interpretation

In the NOPR, the Commission proposed to accept NERC's proposed interpretation of Reliability Standard PRC-005-1 Requirement R1. However, the Commission stated that the proposed interpretation highlights a gap in the required Protection System maintenance and testing pursuant to Requirement R1 of PRC-005-1. To prevent a gap in reliability, FERC stated that any component that detects any quantity needed to take an action, or that initiates any control action (initial tripping, reclosing, lockout, etc.) affecting the reliability of the Bulk-Power System should be included as a component of a Protection System. Accordingly, to address FERC's concern, pursuant to section 215 (d)(5) of the FPA, FERC proposed to direct NERC to develop a modification to the Reliability Standard to include *any component or device that is designed to detect defective lines or apparatuses or other power system conditions of an abnormal or dangerous nature and to initiate appropriate control circuit actions*.

NERC NOPR Comments (pgs. 6-7)

"Regarding FERC's proposed directive to include in the Reliability Standard any device, including auxiliary and backup protection devices, that is designed to sense or take action against any abnormal system condition that will affect reliable operation, NERC states that it understands FERC's concerns related to protective relays that do not respond to electrical quantities and agrees that sudden pressure relays which trip for fault conditions should be maintained in accordance with NERC Reliability Standard requirements. However, NERC is not aware of any existing documents that establish a technical basis for either minimum maintenance activities or maximum maintenance intervals for these devices. NERC expressed concern that the scope of this proposed directive is so broad that any device that is installed on the bulk power system to monitor conditions in any fashion may be included. In fact, many of these devices are advisory in nature and should not be reflected within NERC Standards if they do not serve a necessary reliability purpose. NERC therefore proposed to develop, either independently or in association with other technical organizations such as IEEE, one or more technical documents which:

i. Describe the devices and functions (to include sudden pressure relays which trip for fault conditions) that should address FERC's concern; and

ii. Propose minimum maintenance activities for such devices and maximum maintenance intervals, including the technical basis for each.

These technical documents will address *those protective relays that are necessary for the reliable operation of the bulk power system* and will allow for differentiation between protective relays that detect faults from other devices that monitor the health of the individual equipment and are advisory in nature (e.g., oil temperature). Following development of the above-referenced document(s), NERC would propose a new or revised standard (e.g., PRC-005) using the NERC Reliability Standards development process to include maintenance of such devices, including establishment of minimum maintenance activities and maximum maintenance intervals. NERC did not believe it is necessary for the Commission to issue a directive to address this issue. Rather, NERC proposed to add this issue to the reliability standards issues database for inclusion in the list of issues to address the next time the PRC-005 standard is revised."

Order No. 758 (Para. 12-15)[2]
[Summary of NERC's NOPR comments in P 12-14 have been omitted here for brevity]
"15. The Commission accepts NERC's proposal, and directs NERC to file, within sixty days of publication of this Final Rule, a schedule for informational purposes regarding the development of the technical documents referenced above, including the identification of devices that are designed to sense or take action against any abnormal system condition that will affect reliable operation. NERC shall include in the informational filing a schedule for the development of the changes to the standard that NERC stated it would propose as a result of the above-referenced documents. NERC should update its schedule when it files its annual work plan."

NERC April 12, 2012 Informational Filing[3]
Summary: NERC's filing included a schedule for preparing the necessary technical documents through the SPCS and a schedule for the SPCS work. However, the filing did not include a schedule for the standard development as FERC had required. FERC noted that NERC should update its schedule for the standard development when it files its annual work plan. NERC's RSDP has included the development work schedule. Because NERC filed the item as "informational", FERC did not issue an order accepting or rejecting the filing as it would have done for a "compliance" filing. NERC submitted a further informational filing in July 2012 addressing reclosing relays, but did not include any additional discussion of sudden pressure relays.

Sudden Pressure Relays and Other Devices that Respond to Non-Electrical Quantities
SPCS Input for Standard Development in Response to FERC Order No. 758 – December 2013.

In developing this report, the SPCS evaluated all devices on the IEEE list of device numbers to identify which devices that respond to non-electrical quantities may impact reliable operation of the Bulk-Power System. As a result of this analysis, the SPCS concludes the only devices responding to non-electrical quantities that should be included in the applicability of PRC-005 are sudden pressure relays utilized in a tripping function. When applied in a tripping function, these devices initiate actions to clear faults to support reliable operation of the Bulk-Power System. The other devices evaluated respond to abnormal equipment conditions and take action to protect equipment from mechanical or thermal damage, or premature loss of life, rather than for the purpose of initiating fault clearing or mitigating an abnormal system condition to support reliable operation of the Bulk-Power System.

From SPCS Report:

Table 1: Classification of Devices

Initiate Actions to Clear Faults or Mitigate Abnormal System Conditions to Support Reliable Operation of the Bulk-Power System	Initiate Action for Abnormal Equipment Conditions for Purposes other than Supporting Reliable Operation of the Bulk-Power System	Monitor the Health of Individual Equipment and Provide Information that is Advisory in Nature
Sudden Pressure (63) (when utilized in a trip application)	• Overspeed Device (12) • Underspeed Device (14) • Apparatus Thermal Device (26) • Flame Detector (28) • Bearing Protective Device (38) • Mechanical Condition Monitor (39)	• Apparatus Thermal Device (26) • Bearing Protective Device (38) • Mechanical Condition Monitor (39) • Atmospheric Condition Monitor (45)

2 *Interpretation of Protection System Reliability Standard*, 138 FERC ¶ 61,094 (Order No. 748) (2012) http://www.nerc.com/files/Order_Interp_Protection_Sys_RS_2011.2.3.pdf
3 Informational Filing in Compliance with Order No. 758 – Interpretation of Protection System Reliability Standard, FERC Docket No. RM10-5-000, (2012)
http://www.nerc.com/FilingsOrders/us/NERC%20Filings%20to%20FERC%20DL/Order%20758%20Letter%20Filing_complete.pdf

	• Atmospheric Condition Monitor (45) • Machine or Transformer Thermal Relay (49) • Density Switch or Sensor (61) • Pressure Switch (63) (other than sudden pressure relays utilized in trip application) • Level Switch (71)	• Machine or Transformer Thermal Relay (49) • Density Switch or Sensor (61) • Pressure Switch (63) (other than sudden pressure relays utilized in trip application) • Level Switch (71)

Following the issuance of the report by the Planning Committee, Project 2007-17.3 was proposed for the 2014-2016 RSDP, and adopted by the NERC Board. The SDT added sudden pressure relays to PRC-005-X in accordance with the technical recommendations from the SPCS report.

Sudden Pressure Relaying – Inclusion of Dispersed Generation Facilities

Comments were received expressing concern that the current applicability wording does not clearly indicate the applicability of sudden pressure relaying to dispersed generation facilities. Project 2014-01 (Standards Applicability for Dispersed Generation Resources (DGR) Project) is reviewing the applicability of certain Reliability Standards that apply to a Generator Owner and Generator Operator to recognize the unique technical and reliability aspects of DGR in order to ensure the applicability of the standards is consistent with the reliable operation of the Bulk Power System. The project is related to the revised definition of the BES from Project 2010-17. NERC will assign the appropriate version number at the time the items are presented to the NERC Board of Trustees for adoption. Separating the changes is necessary for the DGR SDT to petition applicable governmental authorities for the applicability changes on a separate timeframe from the other technical changes in this version of PRC-005-X.

Comments relating to Dispersed Generation were forwarded to the Project 2014-01 drafting team along with recommended changes. The PRC-005-X SDT will coordinate with the DGR SDT to ensure no unintended consequences result from changes proposed by the DGR SDT.

Sudden Pressure Relaying in PRC-005

One commenter requested clarification and/or justification of the requirement to test the function of sudden pressure relay actuators based on the fact that such actuators can be difficult to access, and the devices may need to be removed from the transformer. Based on the SDT's knowledge and experience, testing of the devices typically would not require the devices to be removed from the transformer to "verify the pressure or flow sensing mechanism is operable." The SDT developed an FAQ on this subject that is in Section 2.4.1 of the Supplementary Reference and FAQ document.

Several commenters questioned the six-year interval in Table 5 regarding fault pressure relays.
The SDT established the six-year maintenance interval for fault pressure relays (see Table 5, PRC-005-X) based on the recommendation of the System Protection and Control Subcommittee (SPCS). The technical experts of the SPCS were tasked with developing the technical documents to:

i. Describe the devices and functions (to include sudden pressure relays which trip for fault conditions) that should address FERC's concern; and

ii. Propose minimum maintenance activities for such devices and maximum maintenance intervals, including the technical basis for each.

Excerpt from the SPCS technical report: "In order to determine present industry practices related to sudden pressure relay maintenance, the SPCS conducted a survey of Transmission Owners and Generator Owners in all eight Regions requesting information related to their maintenance practices. The SPCS received responses from 75 Transmission Owners and 109 Generator Owners. Note that, for the purpose of the survey, sudden pressure relays included the following: the "sudden pressure relay" (SPR) originally manufactured by Westinghouse, the "rapid pressure rise relay" (RPR) manufactured by Qualitrol, and a variety of Buchholz relays.

Table 2 provides a summary of the results of the responses:

Table 2: Sudden Pressure Relay Maintenance Practices – Survey Results		
	Transmission Owner	**Generator Owner**
Number of responding owners that trip with Sudden Pressure Relays:	67	84
Percentage of responding owners who trip that have a Maintenance Program:	75%	78%
Percentage of maintenance programs that include testing the pressure actuator:	81%	77%
Average Maintenance interval reported:	5.9 years	4.9 years

Additionally, in order to validate the information noted above, the SPCS contacted the following entities for their feedback: the IEEE Power System Relaying Committee, the IEEE Transformer Committee, the Doble Transformer Committee, the NATF System Protection Practices Group, and the EPRI Generator Owner/Operator Technical Focus Group. All of these organizations indicated the results of the SPCS survey are consistent with their respective experiences.

The SPCS discussed the potential difference between the recommended intervals for fault pressure relaying and intervals for transformer maintenance. The SPCS developed the recommended intervals for fault pressure relaying by comparing fault pressure relaying to Protection System Components with similar physical attributes. The SPCS recognized that these intervals may be shorter than some existing or future transformer maintenance intervals, but believed it to be more important to base intervals for fault pressure relaying on similar Protection System Components than transformer maintenance intervals.

The maintenance interval for fault pressure relays can be extended by utilizing performance-based maintenance thereby allowing entities that have maintenance intervals for transformers in excess of six years, to align them.

One commenter questioned the different maintenance intervals associated with control circuitry in the PRC-005 tables. The SDT reviewed the tables and disagrees that an inconsistency exists related to control circuitry. The maximum maintenance interval in Table 1-5 for control circuitry does not indicate 6 years.

One commenter suggested modifying the definition of Sudden Pressure Relaying – Fault pressure relay Component – to make it plural. The SDT chose not to make the change because it is inherently understood that the term can refer to a single device or multiple devices.

One commenter expressed concern that it should be made clear that Table 1-5 and Table 2 do not include maintenance activities for Sudden Pressure Relaying Components. The SDT agrees and made a change to the headers of Table 1-5 and Table 2 (and also to the component attribute for alarm paths in Table 2) to direct attention to Table 5 for the maintenance activities associated with Sudden Pressure Relaying Components. The SDT also added a clarifying note to the header of Table 5.

One commenter expressed concern regarding the testing of the sensing mechanism of sudden pressure relays. The SDT notes that Table 5 requires the owner to verify that the pressure or flow sensing mechanism of the fault pressure relay is operable, but does not specify how to perform the maintenance. As such it is up to the entity to determine how to implement the required maintenance activities. Additionally, the SDT revised the FAQ on this topic and directed the commenter to Section 15.9.1 of the Supplementary Reference and FAQ document.

One commenter requested clarification as to which devices would fall under the classification of Sudden Pressure Relaying, specifically the Buchholz relay and the load tap changer protective device. The SDT's response is that if the device actuation results in the tripping of the transformer, then PRC-005 would be applicable to that device, and also referred the commenter to Section 2.4.1 of the Supplementary Reference and FAQ document.

Why PRC-005-X

This version of PRC-005 is temporarily assigned the numbering "PRC-005-X" because the applicability of PRC-005 may be modified by Project 2007-17.3 (Protection System Maintenance and Testing (PSMT)) and Project 2014-01 (Standards Applicability for Dispersed Generation Resources (DGR)) during 2014.

Administrative

The SDT appreciates the feedback regarding the correction of 4.2.7 in the Supplementary Reference and FAQ document, and the change has been made.

A few comments were received regarding the capitalization of "Part." The SDT appreciates this being brought to our attention and the term Part has been capitalized.

PRC-005 Supplementary Reference and FAQ Document

Several commenters pointed out typographical errors that were corrected.

One commenter asked for the inclusion of the phrase "These are examples and never intended to be an all-inclusive list" in two locations within the Supplementary Reference and FAQ document. The SDT points out that the suggested language is already included in the document; however, changes were made to these write-ups to provide additional clarity.

One commenter indicated that in Section 2.4.1 of the Supplementary Reference and FAQ document, the phrase "Sudden Pressure Relaying can limit damage to equipment" is misleading. The SDT disagrees and no change was made.

One commenter wondered where the "frequently asked questions" were sourced from. The FAQs were developed from numerous comments received from stakeholders and those anticipated by the SDT.

One commenter requested that an FAQ be added to the Supplementary Reference and FAQ document regarding the IEEE device numbers related to Automatic Reclosing. Although the SDT did not address the issue verbatim, the SDT added an FAQ that provided discussion on IEEE device 79 and 25. Additionally, please see Section 2.4.1 of the Supplementary Reference and FAQ document.

One commenter quoted the following legacy statement in the Supplementary Reference and FAQ Document (page 3, section 2.3): "…if the Element is a BES Element, then the Protection System protecting that Element should then be included within this standard." The commenter suggested that this statement expanded the scope of maintenance to an unreasonable level. The SDT reviewed the statement and disagreed with the commenter's assertion. No change was made.

Standards Authorization Request (SAR)

One commenter questioned why there was no response to comments related to the SAR. The SDT notes that the Standards Process Manual (SPM) states in section 4.2: "[f]or SARs that are limited to addressing regulatory directives, or revisions to Reliability Standards that have had some vetting in the industry, authorize posting the SAR for a 30-day informal comment period with no requirement to provide a formal response to the comments received."[4]

NERC Glossary of Terms

One commenter requested that Sudden Pressure Relaying and Automatic Reclosing be added to the NERC Glossary of Terms. The SDT indicates that those terms were developed specifically for purposes of PRC-005 and does not see any benefit from including them in the NERC Glossary of Terms.

One commenter asked why this revision of the standard did not include a revision to the definition of Protection System. During the development of PRC-005-3, the SDT chose not to revise the definition of a Protection System to include Automatic Reclosing and carried that philosophy forward into the development of PRC-005-X.

Definition of Terms Used in Standard

Protection System Maintenance Program (PSMP)

A few commenters questioned the need to modify the definition of the term Component. The SDT notes the Rationale box which states: "The SDT determined that it was explanatory in nature and adequately addressed in the Supplementary Reference and FAQ Document."

One commenter asked why there are two separate definition sections. Page 1 of this standard includes NERC Glossary terms that are being revised while Section A.6 has terms and definitions used within the standard.

One commenter suggested revising the definition of Sudden Pressure Relaying to make it more inclusive of other equipment that the Sudden Pressure Relaying may clear. The SDT response is that the definition is applicable regardless of whether the Sudden Pressure Relaying isolates only the monitored equipment or additional equipment, and declined to make the suggested change.

One commenter suggested defining the term "control circuitry." The definition of Protection Systems sufficiently describes control circuitry as: "Control circuitry associated with protective functions through the trip coil(s) of the circuit breakers or other interrupting devices." The maintenance activities associated with control circuitry are included in Table 1-5. Additionally, see Section 15.3 of the Supplementary Reference and FAQ document.

One commenter offered an alternative definition for the term Component. The SDT does not agree that the alternative definition provided further clarity and respectfully declined to adopt the suggested change.

Several commenters suggested modifying the definition of Countable Event to include relay settings different from specified settings. Countable Events are only associated with Attachment A which is focused on performance-based maintenance. Countable Events are limited to hardware failures or calibration failure; therefore, the SDT declined to make the change.

[4] NERC SPM: http://www.nerc.com/pa/Stand/Documents/Appendix_3A_StandardsProcessesManual.pdf

Applicability Section

One commenter questioned the items listed under the Facilities Section 4.2 in that they do not meet the criteria included in the definition of the term Facility as defined in the NERC Glossary of Terms. Section 4.2 titled "Facilities" within the standards template is capitalized because it is the title of a section. It should not be equated to the defined term "Facilities" within the NERC Glossary of terms.

Additionally, "The SDT revised section 4.2.6.1 of the Applicability to address situations where Balancing Authorities participate in a Reserve Sharing Group. In these cases, a group of Balancing Authorities share reserves to cover any contingency within the boundaries of the group; therefore, generation loss within a Reserve Sharing Group would not impact reliability of the Bulk-Power System unless the aggregate capacity loss exceeds the largest unit within the Reserve Sharing Group. This change is consistent with the rationale described in the SAMS-SPCS report for basing applicability on the "largest unit in the Balancing Authority Area." As such, the references to the "largest BES generating unit within the Balancing Authority Area" were changed to the "largest BES generating unit within the Balancing Authority Area or, where applicable, the Reserve Sharing Group."

Related to these decisions, the following associated changes were also incorporated into the latest version:

- 4.2.6.1 was modified to include the Reserve Sharing Group
- Footnote #1, Page 4 was modified to include the Reserve Sharing Group
- Requirement 3, Part 3.1 and 3.1.1 was modified to include the Reserve Sharing Group
- Requirement 4, Part 4.1 and 4.1.1 was modified to include the Reserve Sharing Group

Several commenters had questions regarding identification of applicable facilities due to configurations where multiple BA Areas are involved. The SDT notes that it is the entity's responsibility to identify the applicable facilities that fall under the requirements of PRC-005. For Automatic Reclosing, sections 4.2.6.1 and 4.2.6.2 describe specific criteria that are used to identify these applicable facilities. Entities must also consider neighboring facilities that may have been identified by another applicable entity in 4.2.6.1 using another BA's largest generating unit.

One commenter suggested adding Sudden Pressure Relaying to the Applicability Section 4.2.5.3. The SDT added Sudden Pressure Relaying to Applicability Section 4.2.5.3 based on the comment and further added Sudden Pressure Relaying to Applicability Section 4.2.5.

Requirement R1

Part 1.2 Table 5

One commenter requested clarification regarding whether or not an entity is required to have a PSMP for all Section 4.2 Facilities or just those Facilities that they own. The SDT response is that Requirement R1 does not specifically require the PSMP to include sections for Facilities listed in Section 4.2 that the entity does not own.

Requirement R3 and R4

Several commenters questioned the formatting of Requirement R3 and R4 regarding the sub-parts 3.1.1 and 3.1.2. NERCs general practice is to use bullets for optional lists and numbering for all-inclusive lists. However, these Parts and sub-parts of Requirement R3 and R4 were ultimately removed.

Other questions were raised regarding Requirement R3 and R4 subparts. However, in the last posting, the SDT included language in the standard that was originally in the implementation plan that required completion of maintenance activities within three years for newly-identified Automatic Reclosing Components following a notification under Requirement R6, which has been removed. After further discussion, the SDT determined that a separate shorter timeframe for maintenance of newly-identified Automatic Reclosing Components created unnecessary complication within the standard. The SDT agreed that entities should be responsible for maintaining the Automatic Reclosing Components subject to the standard, whether existing, newly added or newly within scope based on a change in the largest generating unit in the BA or, if a member of a Reserve Sharing Group, the largest generating unit within the Reserve Sharing Group according to the timeframes in the maintenance tables. Therefore, 3.1, 4.1 and their subparts have been removed, and have not been reinserted into the implementation plan.

Requirement R6

After considering industry comments which included various alternatives and much discussion within the SDT, Requirement R6 and all associated references to Requirement R6 were removed from the standard.

Associated with this change the following response was provided to several commenters: The Automatic Reclosing equipment "owner" is responsible for identifying Automatic Reclosing Components that must be included in their PSMP. The SDT eliminated Requirement R6; therefore, the owner is responsible for obtaining the largest generating unit information.

Data Retention

It is noted that the majority of respondents agreed with the changes to the data retention for Requirements R1 – R5.

A few commenters had concerns regarding the data retention for Requirement R6 but with the elimination of Requirement R6, these concerns were rendered moot.

Two commenters requested clarification for cases where the maintenance intervals are longer than the audit period. The SDT added language to account for those cases where the maintenance intervals are longer than the audit period as well as where the maintenance intervals are shorter than the audit period.

Violation Risk Factors (VRFs)

No comments were received regarding VRFs.

Violation Severity Levels (VSLs)

One commenter pointed out typographical errors. The SDT thanks the commenter and notes that the typographical error has been corrected.

Implementation Plan

One commenter requested a change in Section 9 of the Implementation Plan. The SDT response is that the commenter was apparently referencing the redlined version of the Implementation Plan since the clean version reflected the suggested change.

Misc. additional items:

A commenter questioned why newly identified Sudden Pressure Relaying is not included in the Parts and sub-Parts of Requirement R3. The response is that Sudden Pressure Relaying that are brought into scope with this revision to the standard are treated the same as the initially-identified Automatic Reclosing Relays per PRC-005-3.

Several commenters noted that the rationale for Requirement R6 references Section 4.2.7, Applicability. The Applicability section does not contain a Section 4.2.7 and we believe the reference should instead be Section 4.2.6. Covered by the Summary. The response noted that with the removal of Requirement R6 the noted references were no longer applicable. Additionally, the references to 4.2.7 in Footnote #1 were corrected.

Several commenters recommended that a 1500 MW threshold would be an alternative to the 'largest unit in the Balancing Authority Area'. The SDT notes that they used the criteria recommended by the SPCS and SAMS groups in the technical report.

Several commenters asked for clarification to be added in cases where Sudden Pressure Relaying and Protection System control circuitries share components. The SDT added a note to the header of Table 5 to clarify that in such cases, the shared components need only be tested once in any distinct maintenance interval. Additionally, the Title in Table 1-5 was modified to exclude Automatic Reclosing and Sudden Pressure Relaying.

One commenter questioned whether the term gross capacity refers to nameplate capacity or something else. The SDT directs the commenter to Section 2.4.1 in the Supplementary Reference and FAQ document for the answer.

One commenter questioned whether the term unit refers to an individual generating unit or overall plant. The SDT response is that the term "unit" as used in the comment refers to a single generating unit and directed the commenter to Section 2.4.1 in the Supplementary Reference and FAQ document.

Automatic Reclosing relays that are initially applicable with the approval of PRC-005-3 would be included in the staggered Implementation plan. However, those that are identified as applicable because of the change in the largest generating unit in the Balancing Authority Area or Reserve Sharing Group. The SDT contends that the three calendar years is appropriate because of the limited quantity of applicable Automatic Reclosing Relays.

One commenter requested clarification from the drafting team on the responsibilities of an entity in the event that the entity decides to block or remove a Sudden Pressure Relay device from service after the standard has taken effect. The SDT notes that PRC-005-X is applicable to Protection System, Automatic Reclosing, and Sudden Pressure Relaying components that are in-service; however, the SDT suggests that entities maintain records for components removed from service during the audit period.

One commenter questioned the basis for the 10 circuit-mile parameter included in the previous version of the standard for Automatic Reclosing. This question is out of scope for this revision of the standard. However, please see the Supplementary Reference and FAQ document Section 2.4.1 for a discussion on the 10 circuit-mile issue.

One commenter requested the rationale for adding Sudden Pressure Relaying be memorialized in the standard itself and not just in the change history so future drafting teams understand the circumstances leading to the addition. The drafting team disagreed and made no change to the standard.

Several commenters suggested Section 4.2.1 should only apply to Sudden Pressure Relaying devices required to initiate fault clearing action. The SDT contends that the intent of the comment is reflected in the definition of Sudden Pressure Relaying: "A system that trips an interrupting device(s) to isolate the equipment it is monitoring…"

One commenter suggested including Sudden Pressure Relaying in the Applicability 4.2.4 which currently reads: "Protection Systems installed as a Special Protection System (SPS) for BES reliability" because they contend SPR could be part of an SPS. Based on its knowledge and experience, the SDT could not identify any instances where Sudden Pressure Relaying would be used as part of an SPS, and therefore declined to make the change. In cases where the input logic to an SPS involves the loss of a BES transformer, whether tripped by the Sudden Pressure Relaying or other protective devices, the components involved are covered by PRC-005.

One commenter suggested reordering the maintenance activities listed in Table 1-1. The SDT's response is that the activities in the tables are not intended to indicate any specific order for performance of individual maintenance tasks and declined to make a change to the table.

One commenter pointed out a disparity between Measure M1 and Table 5 regarding monitored control circuitry of Sudden Pressure Relaying. The SDT modified Table 5 to include component attributes and a maintenance activity for monitored Sudden Pressure Relaying control circuitry.

Attachment A – SDT Members

Table 7: Standard Drafting Team Members		
	Participant	**Entity**
Chair	Charles W. Rogers	Consumers Energy
Member	John Anderson	Xcel Energy, Inc.
Member	Forrest D. Brock	Western Farmers Electric Cooperative
Member	Aaron Feathers	Pacific Gas and Electric Company
Member	Samuel Francis	Oncor Electric Delivery
Member	Ervin David Harper	NRG Texas Maintenance Services
Member	James M. Kinney	FirstEnergy Corporation
Member	Mark Lukas	Commonwealth Edison Co.
Member	Kristina Marriott	ENOSERV
Member	John E. Schechter	American Electric Power
Member	William D. Shultz	Southern Company Generation
Member	Eric Udren	Quanta Technology, LLC
Member	Scott Vaughan	California ISO
Member	Mathew J. Westrich	American Transmission Co.
Member	Philip B. Winston	Southern Company Transmission
NERC Staff	Jordan Mallory (Standards Developer Specialist)	NERC
NERC Staff	Al McMeekin (Standards Developer)	NERC
NERC Staff	Phil Tatro (Technical Advisor)	NERC

Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Development Steps Completed

1. SAR posted for comment February 13, 2014 – March 14, 2014.
2. The draft standard was posted for a 45-day concurrent comment and ballot period of April 17, 2014–June 3, 2014.

Description of Current Draft

The Protection System Maintenance and Testing Standard Drafting Team (PSMT SDT) is posting draft 2 of PRC-005-X for a 45-day comment period and ballot in the last ten days of the comment period under the new Standards Process Manual (Effective: June 26, 2013).

This draft contains the technical content of the standard. A parallel effort in the Project 2014-01, Standards Applicability for Dispersed Generation Resources, will post an applicability change to PRC-005-2 and PRC-005-3 for comment and ballot.

Anticipated Actions	Anticipated Date
45-day Formal Comment Period with Parallel Ballot	April 17 – June 2, 2014
45-day Additional Formal Comment Period with Parallel Ballot (if necessary)	July 30, – September 12, 2014
Final ballot	October 2014
BOT adoption	November 2014

Definitions of Terms Used in Standard

This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the Reliability Standards Glossary of Terms (Glossary) are not repeated here. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, this defined term will be removed from the individual standard and added to the Glossary.

Protection System Maintenance Program (PSMP) — An ongoing program by which Protection System, Automatic Reclosing, and Sudden Pressure Relaying Components are kept in working order and proper operation of malfunctioning components is restored. A maintenance program for a specific Component includes one or more of the following activities:

- Verify — Determine that the Component is functioning correctly.
- Monitor — Observe the routine in-service operation of the Component.
- Test — Apply signals to a Component to observe functional performance or output behavior, or to diagnose problems.
- Inspect — Examine for signs of Component failure, reduced performance or degradation.
- Calibrate — Adjust the operating threshold or measurement accuracy of a measuring element to meet the intended performance requirement.

See Section A.6, Definitions Used in this Standard, for additional definitions that are new or modified for use within this standard.

When this standard has received ballot approval, the text boxes will be moved to the Application Guidelines Section of the Standard.

A. Introduction

1. **Title: Protection System, Automatic Reclosing, and Sudden Pressure Relaying Maintenance**
2. **Number: PRC-005-X**
3. **Purpose:** To document and implement programs for the maintenance of all Protection Systems, Automatic Reclosing, and Sudden Pressure Relaying affecting the reliability of the Bulk Electric System (BES) so that they are kept in working order.

Rationale for Applicability Section: This section does not reflect the applicability changes that will be proposed by the Project 2014-01 Standards Applicability for Dispersed Generation Resources standards drafting team. The changes in this posted version and those being made by the Project 2014-01 standards drafting team do not overlap.

Additionally, to align with ongoing NERC standards development in Project 2010-05.2: Special Protection Systems, the term “Special Protection Systems” in PRC-005-X was replaced by the term “Remedial Action Schemes.” These terms are synonymous in the NERC Glossary of Terms.

4. **Applicability:**

4.1. Functional Entities:

4.1.1 Transmission Owner

4.1.2 Generator Owner

4.1.3 Distribution Provider

4.2. Facilities:

4.2.1 Protection Systems and Sudden Pressure Relaying that are installed for the purpose of detecting Faults on BES Elements (lines, buses, transformers, etc.)

4.2.2 Protection Systems used for underfrequency load-shedding systems installed per ERO underfrequency load-shedding requirements.

4.2.3 Protection Systems used for undervoltage load-shedding systems installed to prevent system voltage collapse or voltage instability for BES reliability.

4.2.4 Protection Systems installed as a Remedial Action Scheme (RAS) for BES reliability.

4.2.5 Protection Systems and Sudden Pressure Relaying for generator Facilities that are part of the BES, including:

4.2.5.1 Protection Systems that act to trip the generator either directly or via lockout or auxiliary tripping relays.

4.2.5.2 Protection Systems and Sudden Pressure Relaying for generator step-up transformers for generators that are part of the BES.

4.2.5.3 Protection Systems and Sudden Pressure Relaying for transformers connecting aggregated generation, where the aggregated generation is part of the BES (e.g., transformers connecting facilities such as wind-farms to the BES).

4.2.5.4 Protection Systems and Sudden Pressure Relaying for station service or excitation transformers connected to the generator bus of generators which are part of the BES, that act to trip the generator either directly or via lockout or tripping auxiliary relays.

4.2.6 Automatic Reclosing[1], including:

[1] Automatic Reclosing addressed in Section 4.2.6.1 and 4.2.6.2 may be excluded if the equipment owner can demonstrate that a close-in three-phase fault present for twice the normal clearing time (capturing a minimum trip-close-trip time delay) does not result in a total loss of gross generation in the Interconnection exceeding the gross capacity of the largest relevant BES generating unit where the Automatic Reclosing is applied.

4.2.6.1 Automatic Reclosing applied on the terminals of Elements connected to the BES bus located at generating plant substations where the total installed gross generating plant capacity is greater than the gross capacity of the largest BES generating unit within the Balancing Authority Area or, if a member of a Reserve Sharing Group, the largest generating unit within the Reserve Sharing Group. [2]

4.2.6.2 Automatic Reclosing applied on the terminals of all BES Elements at substations one bus away from generating plants specified in Section 4.2.6.1 when the substation is less than 10 circuit-miles from the generating plant substation.

4.2.6.3. Automatic Reclosing applied as an integral part of an RAS specified in Section 4.2.4.

5. **Effective Date:** See Implementation Plan

6. **Definitions Used in this Standard:**

Automatic Reclosing – Includes the following Components:

- Reclosing relay
- Control circuitry associated with the reclosing relay.

Sudden Pressure Relaying – A system that trips an interrupting device(s) to isolate the equipment it is monitoring and includes the following Components:

- Fault pressure relay – a mechanical relay or device that detects rapid changes in gas pressure, oil pressure, or oil flow that are indicative of Faults within liquid-filled, wire-wound equipment
- Control circuitry associated with a fault pressure relay

Unresolved Maintenance Issue – A deficiency identified during a maintenance activity that causes the Component to not meet the intended performance, cannot be corrected during the maintenance interval, and requires follow-up corrective action.

Segment – Components of a consistent design standard, or a particular model or type from a single manufacturer that typically share other common elements. Consistent performance is expected across the entire population of a Segment. A Segment must contain at least sixty (60) individual Components.

[2] The largest BES generating unit within the Balancing Authority Area or the largest generating unit within the Reserve Sharing Group, as applicable, is subject to change. As a result of such a change, the Automatic Reclosing Components subject to the standard could change effective on the date of such change.

Component Type –

- Any one of the five specific elements of a Protection System.
- Any one of the two specific elements of Automatic Reclosing.
- Any one of the two specific elements of Sudden Pressure Relaying.

Rationale for the deletion of part of the definition of Component: The SDT determined that it was explanatory in nature and adequately addressed in the Supplementary Reference and FAQ Document.

Component – Any individual discrete piece of equipment included in a Protection System, Automatic Reclosing, or Sudden Pressure Relaying.

Countable Event – A failure of a Component requiring repair or replacement, any condition discovered during the maintenance activities in Tables 1-1 through 1-5, Table 3, Tables 4-1 through 4-2, and Table 5, which requires corrective action or a Protection System Misoperation attributed to hardware failure or calibration failure. Misoperations due to product design errors, software errors, relay settings different from specified settings, Protection System Component, Automatic Reclosing, or Sudden Pressure Relaying configuration or application errors are not included in Countable Events.

B. Requirements and Measures

R1. Each Transmission Owner, Generator Owner, and Distribution Provider shall establish a Protection System Maintenance Program (PSMP) for its Protection Systems, Automatic Reclosing, and Sudden Pressure Relaying identified in Section 4.2, Facilities. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning*]

The PSMP shall:

1.1. Identify which maintenance method (time-based, performance-based per PRC-005 Attachment A, or a combination) is used to address each Protection System, Automatic Reclosing, and Sudden Pressure Relaying Component Type. All batteries associated with the station dc supply Component Type of a Protection System shall be included in a time-based program as described in Table 1-4 and Table 3.

1.2. Include the applicable monitored Component attributes applied to each Protection System, Automatic Reclosing, and Sudden Pressure Relaying Component Type consistent with the maintenance intervals specified in Tables 1-1 through 1-5, Table 2, Table 3, Table 4-1 through 4-2, and Table 5 where monitoring is used to extend the maintenance intervals beyond those specified for unmonitored Protection System, Automatic Reclosing, and Sudden Pressure Relaying Components.

M1. Each Transmission Owner, Generator Owner and Distribution Provider shall have a documented Protection System Maintenance Program in accordance with Requirement R1.

For each Protection System, Automatic Reclosing, and Sudden Pressure Relaying Component Type, the documentation shall include the type of maintenance method applied (time-based, performance-based, or a combination of these maintenance methods), and shall include all batteries associated with the station dc supply Component Types in a time-based program as described in Table 1-4 and Table 3. (Part 1.1)

For Component Types that use monitoring to extend the maintenance intervals, the responsible entity(s) shall have evidence for each Protection System, Automatic Reclosing, and Sudden Pressure Relaying Component Type (such as manufacturer's specifications or engineering drawings) of the appropriate monitored Component attributes as specified in Tables 1-1 through 1-5, Table 2, Table 3, Table 4-1 through 4-2, and Table 5. (Part 1.2)

R2. Each Transmission Owner, Generator Owner, and Distribution Provider that uses performance-based maintenance intervals in its PSMP shall follow the procedure established in PRC-005 Attachment A to establish and maintain its performance-based intervals. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

M2. Each Transmission Owner, Generator Owner, and Distribution Provider that uses performance-based maintenance intervals shall have evidence that its current performance-based maintenance program(s) is in accordance with Requirement R2, which may include, but is not limited to, Component lists, dated maintenance records, and dated analysis records and results.

Rationale for R3 Part 3.1: In the last posting, the SDT included language in the standard that was originally in the implementation plan that required completion of maintenance activities within three years for newly-identified Automatic Reclosing Components following a notification under Requirement R6, which has been removed. After further discussion, the SDT determined that a separate shorter timeframe for maintenance of newly-identified Automatic Reclosing Components created unnecessary complication within the standard. The SDT agreed that entities should be responsible for maintaining the Automatic Reclosing Components subject to the standard, whether existing, newly added or newly within scope based on a change in the largest generating unit in the BA or, if a member of a Reserve Sharing Group, the largest generating unit within the Reserve Sharing Group according to the timeframes in the maintenance tables. Therefore, 3.1 and its subparts have been removed and have not been reinserted into the implementation plan.

R3. Each Transmission Owner, Generator Owner, and Distribution Provider that utilizes time-based maintenance program(s) shall maintain its Protection System, Automatic Reclosing, and Sudden Pressure Relaying Components that are included within the time-based maintenance program in accordance with the minimum maintenance activities and maximum maintenance intervals prescribed within Tables 1-1 through

1-5, Table 2, Table 3, Table 4-1 through 4-2, and Table 5. *[Violation Risk Factor: High] [Time Horizon: Operations Planning]*

M3. Each Transmission Owner, Generator Owner, and Distribution Provider that utilizes time-based maintenance program(s) shall have evidence that it has maintained its Protection System, Automatic Reclosing, and Sudden Pressure Relaying Components included within its time-based program in accordance with Requirement R3. The evidence may include, but is not limited to, dated maintenance records, dated maintenance summaries, dated check-off lists, dated inspection records, or dated work orders.

Rationale for R4 Part 4.1: In the last posting, the SDT included language in the standard that was originally in the implementation plan that required completion of maintenance activities within three years for newly-identified Automatic Reclosing Components following a notification under Requirement R6, which has been removed. After further discussion, the SDT determined that a separate shorter timeframe for maintenance of newly-identified Automatic Reclosing Components created unnecessary complication within the standard. The SDT agreed that entities should be responsible for maintaining the Automatic Reclosing Components subject to the standard, whether existing, newly added or newly within scope based on a change in the largest generating unit in the BA or, if a member of a Reserve Sharing Group, the largest generating unit within the Reserve Sharing Group according to the timeframes in the maintenance tables. Therefore, 4.1 and its subparts have been removed and have not been reinserted into the implementation plan.

R4. Each Transmission Owner, Generator Owner, and Distribution Provider that utilizes performance-based maintenance program(s) in accordance with Requirement R2 shall implement and follow its PSMP for its Protection System, Automatic Reclosing, and Sudden Pressure Relaying Components that are included within the performance-based program(s). *[Violation Risk Factor: High] [Time Horizon: Operations Planning]*

M4. Each Transmission Owner, Generator Owner, and Distribution Provider that utilizes performance-based maintenance intervals in accordance with Requirement R2 shall have evidence that it has implemented the Protection System Maintenance Program for the Protection System, Automatic Reclosing, and Sudden Pressure Relaying Components included in its performance-based program in accordance with Requirement R4. The evidence may include, but is not limited to, dated maintenance records, dated maintenance summaries, dated check-off lists, dated inspection records, or dated work orders.

R5. Each Transmission Owner, Generator Owner, and Distribution Provider shall demonstrate efforts to correct identified Unresolved Maintenance Issues. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

M5. Each Transmission Owner, Generator Owner, and Distribution Provider shall have evidence that it has undertaken efforts to correct identified Unresolved Maintenance

Issues in accordance with Requirement R5. The evidence may include, but is not limited to, work orders, replacement Component orders, invoices, project schedules with completed milestones, return material authorizations (RMAs) or purchase orders.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

As defined in the NERC Rules of Procedure, “Compliance Enforcement Authority” means NERC or the Regional Entity in their respective roles of monitoring and enforcing compliance with the NERC Reliability Standards.

1.2. Evidence Retention

The following evidence retention periods identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

The Transmission Owner, Generator Owner, and Distribution Provider shall each keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

For Requirement R1, the Transmission Owner, Generator Owner, and Distribution Provider shall each keep its current dated Protection System Maintenance Program, as well as any superseded versions since the preceding compliance audit, including the documentation that specifies the type of maintenance program applied for each Protection System, Automatic Reclosing, or Sudden Pressure Relaying Component Type.

For Requirement R2, Requirement R3, Requirement R4, and Requirement R5, in cases where the interval of the maintenance activity is longer than the audit cycle, the Transmission Owner, Generator Owner, and Distribution Provider shall each keep documentation of the most recent performance of that maintenance activity for the Protection System, Automatic Reclosing, or Sudden Pressure Relaying Component. In cases where the interval of the maintenance activity is shorter than the audit cycle, documentation of all performances of that maintenance activity for the Protection System, Automatic Reclosing, or Sudden Pressure Relaying Component since the previous scheduled audit date shall be retained.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.3. Compliance Monitoring and Assessment Processes:

Compliance Audits

Self-Certifications

Spot Checking

Compliance Violation Investigations

Self-Reporting

Complaints

1.4. Additional Compliance Information

None

Table of Compliance Elements

Requirement Number	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	The entity's PSMP failed to specify whether one Component Type is being addressed by time-based or performance-based maintenance, or a combination of both (Part 1.1).	The entity's PSMP failed to specify whether two Component Types are being addressed by time-based or performance-based maintenance, or a combination of both (Part 1.1).	The entity's PSMP failed to specify whether three Component Types are being addressed by time-based or performance-based maintenance, or a combination of both. (Part 1.1). OR The entity's PSMP failed to include the applicable monitoring attributes applied to each Component Type consistent with the maintenance intervals specified in Tables 1-1 through 1-5, Table 2, Table 3, Tables 4-1 through 4-2, and Table 5 where monitoring is used to extend the maintenance intervals beyond those specified for unmonitored Components (Part 1.2).	The entity failed to establish a PSMP. OR The entity's PSMP failed to specify whether four or more Component Types are being addressed by time-based or performance-based maintenance, or a combination of both (Part 1.1). OR The entity's PSMP failed to include applicable station batteries in a time-based program (Part 1.1).
R2	The entity uses performance-based maintenance intervals in its PSMP but failed to reduce Countable Events to no more than 4% within three years.	NA	The entity uses performance-based maintenance intervals in its PSMP but failed to reduce Countable Events to no more than 4% within four years.	The entity uses performance-based maintenance intervals in its PSMP but: 1) Failed to establish the technical justification described within Requirement R2 for the initial use of the performance-based PSMP OR 2) Failed to reduce Countable Events to no more than 4% within five years OR

Requirement Number	Lower VSL	Moderate VSL	High VSL	Severe VSL
				3) Maintained a Segment with less than 60 Components OR 4) Failed to: • Annually update the list of Components, OR • Annually perform maintenance on the greater of 5% of the Segment population or 3 Components, OR • Annually analyze the program activities and results for each Segment.
R3	For Components included within a time-based maintenance program, the entity failed to maintain 5% or less of the total Components included within a specific Component Type in accordance with the minimum maintenance activities and maximum maintenance intervals prescribed within Tables 1-1 through 1-5, Table 2, Table 3, Tables 4-1 through 4-2, and Table 5.	For Components included within a time-based maintenance program, the entity failed to maintain more than 5% but 10% or less of the total Components included within a specific Component Type in accordance with the minimum maintenance activities and maximum maintenance intervals prescribed within Tables 1-1 through 1-5, Table 2, Table 3, Tables 4-1 through 4-2, and Table 5.	For Components included within a time-based maintenance program, the entity failed to maintain more than 10% but 15% or less of the total Components included within a specific Component Type in accordance with the minimum maintenance activities and maximum maintenance intervals prescribed within Tables 1-1 through 1-5, Table 2, Table 3, Tables 4-1 through 4-2, and Table 5.	For Components included within a time-based maintenance program, the entity failed to maintain more than 15% of the total Components included within a specific Component Type in accordance with the minimum maintenance activities and maximum maintenance intervals prescribed within Tables 1-1 through 1-5, Table 2, Table 3, Tables 4-1 through 4-2, and Table 5.

Requirement Number	Lower VSL	Moderate VSL	High VSL	Severe VSL
R4	For Components included within a performance-based maintenance program, the entity failed to maintain 5% or less of the annual scheduled maintenance for a specific Component Type in accordance with their performance-based PSMP.	For Components included within a performance-based maintenance program, the entity failed to maintain more than 5% but 10% or less of the annual scheduled maintenance for a specific Component Type in accordance with their performance-based PSMP.	For Components included within a performance-based maintenance program, the entity failed to maintain more than 10% but 15% or less of the annual scheduled maintenance for a specific Component Type in accordance with their performance-based PSMP.	For Components included within a performance-based maintenance program, the entity failed to maintain more than 15% of the annual scheduled maintenance for a specific Component Type in accordance with their performance-based PSMP.
R5	The entity failed to undertake efforts to correct 5 or fewer identified Unresolved Maintenance Issues.	The entity failed to undertake efforts to correct greater than 5 but less than or equal to 10 identified Unresolved Maintenance Issues.	The entity failed to undertake efforts to correct greater than 10 but less than or equal to 15 identified Unresolved Maintenance Issues.	The entity failed to undertake efforts to correct greater than 15 identified Unresolved Maintenance Issues.

D. Regional Variances

None.

E. Interpretations

None.

F. Supplemental Reference Documents

The following documents present a detailed discussion about determination of maintenance intervals and other useful information regarding establishment of a maintenance program.

1. *Supplementary Reference and FAQ - PRC-005-X Protection System Maintenance,* Protection System Maintenance and Testing Standard Drafting Team (April 2014)
2. *Considerations for Maintenance and Testing of Auto-reclosing Schemes*, NERC System Analysis and Modeling Subcommittee, and NERC System Protection and Control Subcommittee (November 2012)
3. *Sudden Pressure Relays and Other Devices that Respond to Non-Electrical Quantities – SPCS Input for Standard Development in Response to FERC Order No. 758,* NERC System Protection and Control Subcommittee (December 2013)

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
1	December 1, 2005	1. Changed incorrect use of certain hyphens (-) to “en dash” (–) and “em dash (—).” 2. Added “periods” to items where appropriate. 3. Changed “Timeframe” to “Time Frame” in item D, 1.2.	01/20/05
1a	February 17, 2011	Added Appendix 1 - Interpretation regarding applicability of standard to protection of radially connected transformers	Project 2009-17 interpretation
1a	February 17, 2011	Adopted by Board of Trustees	

1a	September 26, 2011	FERC Order issued approving interpretation of R1 and R2 (FERC's Order is effective as of September 26, 2011)	
1.1a	February 1, 2012	Errata change: Clarified inclusion of generator interconnection Facility in Generator Owner's responsibility	Revision under Project 2010-07
1b	February 3, 2012	FERC Order issued approving interpretation of R1, R1.1, and R1.2 (FERC's Order dated March 14, 2012). Updated version from 1a to 1b.	Project 2009-10 Interpretation
1.1b	April 23, 2012	Updated standard version to 1.1b to reflect FERC approval of PRC-005-1b.	Revision under Project 2010-07

1.1b	May 9, 2012	PRC-005-1.1b was adopted by the Board of Trustees as part of Project 2010-07 (Generator Requirements at the Transmission Interface).	
2	November 7, 2012	Adopted by Board of Trustees	Project 2007-17 - Complete revision, absorbing maintenance requirements from PRC-005-1.1b, PRC-008-0, PRC-011-0, PRC-017-0
2	October 17, 2013	Errata Change: The Standards Committee approved an errata change to the implementation plan for PRC-005-2 to add the phrase "or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities;" to the second sentence under the "Retirement of Existing	
3	November 7, 2013	Adopted by the NERC Board of Trustees	Revised to address the FERC directive in Order No.758 to include Automatic Reclosing in maintenance programs.
3.1	February 12, 2014	Approved by the Standards Committee	Errata changes to correct capitalization of defined terms
X			Project 2007-17.3 – Revised to address the FERC directive in Order No. 758 to include sudden pressure relays in maintenance programs.

Table 1-1 Component Type - Protective Relay Excluding distributed UFLS and distributed UVLS (see Table 3)		
Component Attributes	**Maximum Maintenance Interval[3]**	**Maintenance Activities**
Any unmonitored protective relay not having all the monitoring attributes of a category below.	6 Calendar Years	For all unmonitored relays: • Verify that settings are as specified For non-microprocessor relays: • Test and, if necessary calibrate For microprocessor relays: • Verify operation of the relay inputs and outputs that are essential to proper functioning of the Protection System. • Verify acceptable measurement of power system input values.
Monitored microprocessor protective relay with the following: • Internal self-diagnosis and alarming (see Table 2). • Voltage and/or current waveform sampling three or more times per power cycle, and conversion of samples to numeric values for measurement calculations by microprocessor electronics. • Alarming for power supply failure (see Table 2).	12 Calendar Years	Verify: • Settings are as specified. • Operation of the relay inputs and outputs that are essential to proper functioning of the Protection System. • Acceptable measurement of power system input values.

[3] For the tables in this standard, a calendar year starts on the first day of a new year (January 1) after a maintenance activity has been completed.
For the tables in this standard, a calendar month starts on the first day of the first month after a maintenance activity has been completed.

Monitored microprocessor protective relay with preceding row attributes and the following: • Ac measurements are continuously verified by comparison to an independent ac measurement source, with alarming for excessive error (See Table 2). • Some or all binary or status inputs and control outputs are monitored by a process that continuously demonstrates ability to perform as designed, with alarming for failure (See Table 2). • Alarming for change of settings (See Table 2).	12 Calendar Years	Verify only the unmonitored relay inputs and outputs that are essential to proper functioning of the Protection System.

<table>
<tr><th colspan="3">Table 1-2
Component Type - Communications Systems
Excluding distributed UFLS and distributed UVLS (see Table 3)</th></tr>
<tr><th>Component Attributes</th><th>Maximum Maintenance Interval</th><th>Maintenance Activities</th></tr>
<tr><td rowspan="2">Any unmonitored communications system necessary for correct operation of protective functions, and not having all the monitoring attributes of a category below.</td><td>4 Calendar Months</td><td>Verify that the communications system is functional.</td></tr>
<tr><td>6 Calendar Years</td><td>Verify that the communications system meets performance criteria pertinent to the communications technology applied (e.g. signal level, reflected power, or data error rate).
Verify operation of communications system inputs and outputs that are essential to proper functioning of the Protection System.</td></tr>
<tr><td>Any communications system with continuous monitoring or periodic automated testing for the presence of the channel function, and alarming for loss of function (See Table 2).</td><td>12 Calendar Years</td><td>Verify that the communications system meets performance criteria pertinent to the communications technology applied (e.g. signal level, reflected power, or data error rate).
Verify operation of communications system inputs and outputs that are essential to proper functioning of the Protection System.</td></tr>
<tr><td>Any communications system with all of the following:
• Continuous monitoring or periodic automated testing for the performance of the channel using criteria pertinent to the communications technology applied (e.g. signal level, reflected power, or data error rate, and alarming for excessive performance degradation). (See Table 2)
• Some or all binary or status inputs and control outputs are monitored by a process that continuously demonstrates ability to perform as designed, with alarming for failure (See Table 2).</td><td>12 Calendar Years</td><td>Verify only the unmonitored communications system inputs and outputs that are essential to proper functioning of the Protection System</td></tr>
</table>

Table 1-3 Component Type - Voltage and Current Sensing Devices Providing Inputs to Protective Relays Excluding distributed UFLS and distributed UVLS (see Table 3)		
Component Attributes	**Maximum Maintenance Interval**	**Maintenance Activities**
Any voltage and current sensing devices not having monitoring attributes of the category below.	12 Calendar Years	Verify that current and voltage signal values are provided to the protective relays.
Voltage and Current Sensing devices connected to microprocessor relays with AC measurements are continuously verified by comparison of sensing input value, as measured by the microprocessor relay, to an independent ac measurement source, with alarming for unacceptable error or failure (see Table 2).	No periodic maintenance specified	None.

Table 1-4(a) Component Type – Protection System Station dc Supply Using Vented Lead-Acid (VLA) Batteries Excluding distributed UFLS and distributed UVLS (see Table 3) Protection System Station dc supply used only for non-BES interrupting devices for RAS, non-distributed UFLS systems, or non-distributed UVLS systems is excluded (see Table 1-4(e)).		
Component Attributes	**Maximum Maintenance Interval**	**Maintenance Activities**
Protection System Station dc supply using Vented Lead-Acid (VLA) batteries not having monitoring attributes of Table 1-4(f).	4 Calendar Months	Verify: • Station dc supply voltage Inspect: • Electrolyte level • For unintentional grounds
	18 Calendar Months	Verify: • Float voltage of battery charger • Battery continuity • Battery terminal connection resistance • Battery intercell or unit-to-unit connection resistance Inspect: • Cell condition of all individual battery cells where cells are visible – or measure battery cell/unit internal ohmic values where the cells are not visible • Physical condition of battery rack

Table 1-4(a) Component Type – Protection System Station dc Supply Using Vented Lead-Acid (VLA) Batteries Excluding distributed UFLS and distributed UVLS (see Table 3) Protection System Station dc supply used only for non-BES interrupting devices for RAS, non-distributed UFLS systems, or non-distributed UVLS systems is excluded (see Table 1-4(e)).		
Component Attributes	**Maximum Maintenance Interval**	**Maintenance Activities**
	18 Calendar Months -or- 6 Calendar Years	Verify that the station battery can perform as manufactured by evaluating cell/unit measurements indicative of battery performance (e.g. internal ohmic values or float current) against the station battery baseline. -or- Verify that the station battery can perform as manufactured by conducting a performance or modified performance capacity test of the entire battery bank.

Table 1-4(b) Component Type – Protection System Station dc Supply Using Valve-Regulated Lead-Acid (VRLA) Batteries Excluding distributed UFLS and distributed UVLS (see Table 3) Protection System Station dc supply used only for non-BES interrupting devices for RAS, non-distributed UFLS systems, or non-distributed UVLS systems is excluded (see Table 1-4(e)).		
Component Attributes	Maximum Maintenance Interval	Maintenance Activities
Protection System Station dc supply with Valve Regulated Lead-Acid (VRLA) batteries not having monitoring attributes of Table 1-4(f).	4 Calendar Months	Verify: • Station dc supply voltage Inspect: • For unintentional grounds
	6 Calendar Months	Inspect: • Condition of all individual units by measuring battery cell/unit internal ohmic values.
	18 Calendar Months	Verify: • Float voltage of battery charger • Battery continuity • Battery terminal connection resistance • Battery intercell or unit-to-unit connection resistance Inspect: • Physical condition of battery rack

Table 1-4(b) Component Type – Protection System Station dc Supply Using Valve-Regulated Lead-Acid (VRLA) Batteries Excluding distributed UFLS and distributed UVLS (see Table 3) Protection System Station dc supply used only for non-BES interrupting devices for RAS, non-distributed UFLS systems, or non-distributed UVLS systems is excluded (see Table 1-4(e)).		
Component Attributes	**Maximum Maintenance Interval**	**Maintenance Activities**
	6 Calendar Months -or- 3 Calendar Years	Verify that the station battery can perform as manufactured by evaluating cell/unit measurements indicative of battery performance (e.g. internal ohmic values or float current) against the station battery baseline. -or- Verify that the station battery can perform as manufactured by conducting a performance or modified performance capacity test of the entire battery bank.

Table 1-4(c) Component Type – Protection System Station dc Supply Using Nickel-Cadmium (NiCad) Batteries Excluding distributed UFLS and distributed UVLS (see Table 3) Protection System Station dc supply used only for non-BES interrupting devices for RAS, non-distributed UFLS system, or non-distributed UVLS systems is excluded (see Table 1-4(e)).		
Component Attributes	**Maximum Maintenance Interval**	**Maintenance Activities**
Protection System Station dc supply **Nickel-Cadmium (NiCad) batteries** not having monitoring attributes of Table 1-4(f).	4 Calendar Months	Verify: • Station dc supply voltage Inspect: • Electrolyte level • For unintentional grounds
	18 Calendar Months	Verify: • Float voltage of battery charger • Battery continuity • Battery terminal connection resistance • Battery intercell or unit-to-unit connection resistance Inspect: • Cell condition of all individual battery cells. • Physical condition of battery rack

Table 1-4(c) Component Type – Protection System Station dc Supply Using Nickel-Cadmium (NiCad) Batteries Excluding distributed UFLS and distributed UVLS (see Table 3) Protection System Station dc supply used only for non-BES interrupting devices for RAS, non-distributed UFLS system, or non-distributed UVLS systems is excluded (see Table 1-4(e)).		
Component Attributes	**Maximum Maintenance Interval**	**Maintenance Activities**
	6 Calendar Years	Verify that the station battery can perform as manufactured by conducting a performance or modified performance capacity test of the entire battery bank.

Table 1-4(d) Component Type – Protection System Station dc Supply Using Non Battery Based Energy Storage Excluding distributed UFLS and distributed UVLS (see Table 3) Protection System Station dc supply used only for non-BES interrupting devices for RAS, non-distributed UFLS system, or non-distributed UVLS systems is excluded (see Table 1-4(e)).		
Component Attributes	**Maximum Maintenance Interval**	**Maintenance Activities**
Any Protection System station dc supply not using a battery and not having monitoring attributes of Table 1-4(f).	4 Calendar Months	Verify: • Station dc supply voltage Inspect: • For unintentional grounds
	18 Calendar Months	Inspect: Condition of non-battery based dc supply
	6 Calendar Years	Verify that the dc supply can perform as manufactured when ac power is not present.

Table 1-4(e) Component Type – Protection System Station dc Supply for non-BES Interrupting Devices for RAS, non-distributed UFLS, and non-distributed UVLS systems		
Component Attributes	**Maximum Maintenance Interval**	**Maintenance Activities**
Any Protection System dc supply used for tripping only non-BES interrupting devices as part of a RAS, non-distributed UFLS, or non-distributed UVLS system and not having monitoring attributes of Table 1-4(f).	When control circuits are verified (See Table 1-5)	Verify Station dc supply voltage.

Table 1-4(f) Exclusions for Protection System Station dc Supply Monitoring Devices and Systems		
Component Attributes	**Maximum Maintenance Interval**	**Maintenance Activities**
Any station dc supply with high and low voltage monitoring and alarming of the battery charger voltage to detect charger overvoltage and charger failure (See Table 2).	No periodic maintenance specified	No periodic verification of station dc supply voltage is required.
Any battery based station dc supply with electrolyte level monitoring and alarming in every cell (See Table 2).		No periodic inspection of the electrolyte level for each cell is required.
Any station dc supply with unintentional dc ground monitoring and alarming (See Table 2).		No periodic inspection of unintentional dc grounds is required.
Any station dc supply with charger float voltage monitoring and alarming to ensure correct float voltage is being applied on the station dc supply (See Table 2).		No periodic verification of float voltage of battery charger is required.
Any battery based station dc supply with monitoring and alarming of battery string continuity (See Table 2).		No periodic verification of the battery continuity is required.
Any battery based station dc supply with monitoring and alarming of the intercell and/or terminal connection detail resistance of the entire battery (See Table 2).		No periodic verification of the intercell and terminal connection resistance is required.
Any Valve Regulated Lead-Acid (VRLA) or Vented Lead-Acid (VLA) station battery with internal ohmic value or float current monitoring and alarming, and evaluating present values relative to baseline internal ohmic values for every cell/unit (See Table 2).		No periodic evaluation relative to baseline of battery cell/unit measurements indicative of battery performance is required to verify the station battery can perform as manufactured.
Any Valve Regulated Lead-Acid (VRLA) or Vented Lead-Acid (VLA) station battery with monitoring and alarming of each cell/unit internal ohmic value (See Table 2).		No periodic inspection of the condition of all individual units by measuring battery cell/unit internal ohmic values of a station VRLA or Vented Lead-Acid (VLA) battery is required.

Table 1-5 Component Type - Control Circuitry Associated With Protective Functions Excluding distributed UFLS and distributed UVLS (see Table 3), Automatic Reclosing (see Table 4), and Sudden Pressure Relaying (see Table 5) Note: Table requirements apply to all Control Circuitry Components of Protection Systems, and RAS except as noted.		
Component Attributes	**Maximum Maintenance Interval**	**Maintenance Activities**
Trip coils or actuators of circuit breakers, interrupting devices, or mitigating devices (regardless of any monitoring of the control circuitry).	6 Calendar Years	Verify that each trip coil is able to operate the circuit breaker, interrupting device, or mitigating device.
Electromechanical lockout devices which are directly in a trip path from the protective relay to the interrupting device trip coil (regardless of any monitoring of the control circuitry).	6 Calendar Years	Verify electrical operation of electromechanical lockout devices.
Unmonitored control circuitry associated with RAS. (See Table 4-2(b) for RAS which include Automatic Reclosing.)	12 Calendar Years	Verify all paths of the control circuits essential for proper operation of the RAS.
Unmonitored control circuitry associated with protective functions inclusive of all auxiliary relays.	12 Calendar Years	Verify all paths of the trip circuits inclusive of all auxiliary relays through the trip coil(s) of the circuit breakers or other interrupting devices.
Control circuitry associated with protective functions and/or RAS whose integrity is monitored and alarmed (See Table 2).	No periodic maintenance specified	None.

Table 2 – Alarming Paths and Monitoring In Tables 1-1 through 1-5, Table 3, Tables 4-1 through 4-2, and Table 5 alarm attributes used to justify extended maximum maintenance intervals and/or reduced maintenance activities are subject to the following maintenance requirements		
Component Attributes	**Maximum Maintenance Interval**	**Maintenance Activities**
Any alarm path through which alarms in Tables 1-1 through 1-5, Table 3, Tables 4-1 through 4-2, and Table 5 are conveyed from the alarm origin to the location where corrective action can be initiated, and not having all the attributes of the "Alarm Path with monitoring" category below. Alarms are reported within 24 hours of detection to a location where corrective action can be initiated.	12 Calendar Years	Verify that the alarm path conveys alarm signals to a location where corrective action can be initiated.
Alarm Path with monitoring: The location where corrective action is taken receives an alarm within 24 hours for failure of any portion of the alarming path from the alarm origin to the location where corrective action can be initiated.	No periodic maintenance specified	None.

Table 3 Maintenance Activities and Intervals for distributed UFLS and distributed UVLS Systems		
Component Attributes	**Maximum Maintenance Interval**	**Maintenance Activities**
Any unmonitored protective relay not having all the monitoring attributes of a category below.	6 Calendar Years	Verify that settings are as specified. For non-microprocessor relays: • Test and, if necessary calibrate. For microprocessor relays: • Verify operation of the relay inputs and outputs that are essential to proper functioning of the Protection System. • Verify acceptable measurement of power system input values.
Monitored microprocessor protective relay with the following: • Internal self-diagnosis and alarming (See Table 2). • Voltage and/or current waveform sampling three or more times per power cycle, and conversion of samples to numeric values for measurement calculations by microprocessor electronics. Alarming for power supply failure (See Table 2).	12 Calendar Years	Verify: • Settings are as specified. • Operation of the relay inputs and outputs that are essential to proper functioning of the Protection System. • Acceptable measurement of power system input values
Monitored microprocessor protective relay with preceding row attributes and the following: • Ac measurements are continuously verified by comparison to an independent ac measurement source, with alarming for excessive error (See Table 2).	12 Calendar Years	Verify only the unmonitored relay inputs and outputs that are essential to proper functioning of the Protection System.

Table 3 Maintenance Activities and Intervals for distributed UFLS and distributed UVLS Systems		
Component Attributes	**Maximum Maintenance Interval**	**Maintenance Activities**
• Some or all binary or status inputs and control outputs are monitored by a process that continuously demonstrates ability to perform as designed, with alarming for failure (See Table 2). Alarming for change of settings (See Table 2).		
Voltage and/or current sensing devices associated with UFLS or UVLS systems.	12 Calendar Years	Verify that current and/or voltage signal values are provided to the protective relays.
Protection System dc supply for tripping non-BES interrupting devices used only for a UFLS or UVLS system.	12 Calendar Years	Verify Protection System dc supply voltage.
Control circuitry between the UFLS or UVLS relays and electromechanical lockout and/or tripping auxiliary devices (excludes non-BES interrupting device trip coils).	12 Calendar Years	Verify the path from the relay to the lockout and/or tripping auxiliary relay (including essential supervisory logic).
Electromechanical lockout and/or tripping auxiliary devices associated only with UFLS or UVLS systems (excludes non-BES interrupting device trip coils).	12 Calendar Years	Verify electrical operation of electromechanical lockout and/or tripping auxiliary devices.
Control circuitry between the electromechanical lockout and/or tripping auxiliary devices and the non-BES interrupting devices in UFLS or UVLS systems, or between UFLS or UVLS relays (with no interposing electromechanical lockout or auxiliary device) and the non-BES interrupting devices (excludes non-BES interrupting device trip coils).	No periodic maintenance specified	None.
Trip coils of non-BES interrupting devices in UFLS or UVLS systems.	No periodic maintenance specified	None.

Table 4-1

Maintenance Activities and Intervals for Automatic Reclosing Components

Component Type – Reclosing Relay

Component Attributes	Maximum Maintenance Interval	Maintenance Activities
Any unmonitored reclosing relay not having all the monitoring attributes of a category below.	6 Calendar Years	Verify that settings are as specified. For non-microprocessor relays: • Test and, if necessary calibrate For microprocessor relays: • Verify operation of the relay inputs and outputs that are essential to proper functioning of the Automatic Reclosing.
Monitored microprocessor reclosing relay with the following: • Internal self-diagnosis and alarming (See Table 2). • Alarming for power supply failure (See Table 2).	12 Calendar Years	Verify: • Settings are as specified. • Operation of the relay inputs and outputs that are essential to proper functioning of the Automatic Reclosing.

Table 4-2(a) Maintenance Activities and Intervals for Automatic Reclosing Components Component Type – Control Circuitry Associated with Reclosing Relays that are NOT an Integral Part of an RAS		
Component Attributes	**Maximum Maintenance Interval**	**Maintenance Activities**
Unmonitored Control circuitry associated with Automatic Reclosing that is not an integral part of an RAS.	12 Calendar Years	Verify that Automatic Reclosing, upon initiation, does not issue a premature closing command to the close circuitry.
Control circuitry associated with Automatic Reclosing that is not part of an RAS and is monitored and alarmed for conditions that would result in a premature closing command. (See Table 2)	No periodic maintenance specified	None.

Table 4-2(b) Maintenance Activities and Intervals for Automatic Reclosing Components Component Type – Control Circuitry Associated with Reclosing Relays that ARE an Integral Part of an RAS		
Component Attributes	**Maximum Maintenance Interval**	**Maintenance Activities**
Close coils or actuators of circuit breakers or similar devices that are used in conjunction with Automatic Reclosing as part of an RAS (regardless of any monitoring of the control circuitry).	6 Calendar Years	Verify that each close coil or actuator is able to operate the circuit breaker or mitigating device.
Unmonitored close control circuitry associated with Automatic Reclosing used as an integral part of an RAS.	12 Calendar Years	Verify all paths of the control circuits associated with Automatic Reclosing that are essential for proper operation of the RAS.
Control circuitry associated with Automatic Reclosing that is an integral part of an RAS whose integrity is monitored and alarmed. (See Table 2)	No periodic maintenance specified	None.

Table 5

Maintenance Activities and Intervals for Sudden Pressure Relaying

Note: In cases where Components of Sudden Pressure Relaying are common to Components listed in Table 1-5, the Components only need to be tested once during a distinct maintenance interval.

Component Attributes	Maximum Maintenance Interval	Maintenance Activities
Any fault pressure relay.	6 Calendar Years	Verify the pressure or flow sensing mechanism is operable.
Electromechanical lockout devices which are directly in a trip path from the fault pressure relay to the interrupting device trip coil (regardless of any monitoring of the control circuitry).	6 Calendar Years	Verify electrical operation of electromechanical lockout devices.
Control circuitry associated with Sudden Pressure Relaying.	12 Calendar Years	Verify all paths of the trip circuits inclusive of all auxiliary relays through the trip coil(s) of the circuit breakers or other interrupting devices.
Control circuitry associated with Sudden Pressure Relaying whose integrity is monitored and alarmed (See Table 2).	No periodic maintenance specified	None.

PRC-005 — Attachment A

Criteria for a Performance-Based Protection System Maintenance Program

Purpose: To establish a technical basis for initial and continued use of a performance-based Protection System Maintenance Program (PSMP).

To establish the technical justification for the initial use of a performance-based PSMP:

1. Develop a list with a description of Components included in each designated Segment, with a minimum Segment population of 60 Components.
2. Maintain the Components in each Segment according to the time-based maximum allowable intervals established in Tables 1-1 through 1-5, Table 3, Tables 4-1 through 4-2, and Table 5 until results of maintenance activities for the Segment are available for a minimum of 30 individual Components of the Segment.
3. Document the maintenance program activities and results for each Segment, including maintenance dates and Countable Events for each included Component.
4. Analyze the maintenance program activities and results for each Segment to determine the overall performance of the Segment and develop maintenance intervals.
5. Determine the maximum allowable maintenance interval for each Segment such that the Segment experiences Countable Events on no more than 4% of the Components within the Segment, for the greater of either the last 30 Components maintained or all Components maintained in the previous year.

To maintain the technical justification for the ongoing use of a performance-based PSMP:

1. At least annually, update the list of Components and Segments and/or description if any changes occur within the Segment.
2. Perform maintenance on the greater of 5% of the Components (addressed in the performance based PSMP) in each Segment or 3 individual Components within the Segment in each year.
3. For the prior year, analyze the maintenance program activities and results for each Segment to determine the overall performance of the Segment.
4. Using the prior year's data, determine the maximum allowable maintenance interval for each Segment such that the Segment experiences Countable Events on no more than 4% of the Components within the Segment, for the greater of either the last 30 Components maintained or all Components maintained in the previous year.

If the Components in a Segment maintained through a performance-based PSMP experience 4% or more Countable Events, develop, document, and implement an action plan to reduce the Countable Events to less than 4% of the Segment population within 3 years.

Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Development Steps Completed

1. SAR posted for comment February 13, 2014 – March 14, 2014.
2. The draft standard was posted for a 45-day concurrent comment and ballot period of April 17, 2014–June 3, 2014.

Description of Current Draft

The Protection System Maintenance and Testing Standard Drafting Team (PSMT SDT) is posting draft 2~~1~~ of PRC-005-X for a 45-day comment period and ballot in the last ten days of the comment period under the new Standards Process Manual (Effective: June 26, 2013).

This draft contains the technical content of the standard. A parallel effort in the Project 2014-01, Standards Applicability for Dispersed Generation Resources, will post an applicability change to PRC-005-2 and PRC-005-3 for comment and ballot.

Anticipated Actions	Anticipated Date
45-day Formal Comment Period with Parallel Ballot	April 17 – June 2, 2014
45-day Additional Formal Comment Period with Parallel Ballot (if necessary)	July 30, – September 12, 2014
Final ballot	October 2014
BOT adoption	November 2014

Definitions of Terms Used in Standard

This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the Reliability Standards Glossary of Terms (Glossary) are not repeated here. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, this defined term will be removed from the individual standard and added to the Glossary.

Protection System Maintenance Program (PSMP) — An ongoing program by which Protection System, Automatic Reclosing, and Sudden Pressure Relaying Components are kept in working order and proper operation of malfunctioning components is restored. A maintenance program for a specific Component includes one or more of the following activities:

- Verify — Determine that the Component is functioning correctly.
- Monitor — Observe the routine in-service operation of the Component.
- Test — Apply signals to a Component to observe functional performance or output behavior, or to diagnose problems.
- Inspect — Examine for signs of Component failure, reduced performance or degradation.
- Calibrate — Adjust the operating threshold or measurement accuracy of a measuring element to meet the intended performance requirement.

See Section A.6, Definitions Used in this Standard, for additional definitions that are new or modified for use within this standard.

When this standard has received ballot approval, the text boxes will be moved to the Application Guidelines Section of the Standard.

A. Introduction

1. **Title: Protection System, Automatic Reclosing, and Sudden Pressure Relaying Maintenance**
2. **Number: PRC-005-X**
3. **Purpose:** To document and implement programs for the maintenance of all Protection Systems, Automatic Reclosing, and Sudden Pressure Relaying affecting the reliability of the Bulk Electric System (BES) so that they are kept in working order.

Rationale for Applicability Section: This section does not reflect the applicability changes that will be proposed by the Project 2014-01 Standards Applicability for Dispersed Generation Resources standards drafting team. The changes in this posted version and those being made by the Project 2014-01 standards drafting team do not overlap.

Additionally, to align with ongoing NERC standards development in Project 2010-05.2: Special Protection Systems, the term "Special Protection Systems" in PRC-005-X was replaced by the term "Remedial Action Schemes." These terms are synonymous in the NERC Glossary of Terms.

4. **Applicability:**

4.1. Functional Entities:

4.1.1 Transmission Owner

4.1.2 Generator Owner

4.1.3 Distribution Provider

~~**4.1.4** Balancing Authority~~

4.2. Facilities:

4.2.1 Protection Systems and Sudden Pressure Relaying that are installed for the purpose of detecting Faults on BES Elements (lines, buses, transformers, etc.)

4.2.2 Protection Systems used for underfrequency load-shedding systems installed per ERO underfrequency load-shedding requirements.

4.2.3 Protection Systems used for undervoltage load-shedding systems installed to prevent system voltage collapse or voltage instability for BES reliability.

4.2.4 Protection Systems installed as a Remedial Action Scheme (RAS~~Special Protection System (SPS~~) for BES reliability.

4.2.5 Protection Systems and Sudden Pressure Relaying for generator Facilities that are part of the BES, including:

4.2.5.1 Protection Systems that act to trip the generator either directly or via lockout or auxiliary tripping relays.

4.2.5.2 Protection Systems and Sudden Pressure Relaying for generator step-up transformers for generators that are part of the BES.

4.2.5.3 Protection Systems and Sudden Pressure Relaying for transformers connecting aggregated generation, where the aggregated generation is part of the BES (e.g., transformers connecting facilities such as wind-farms to the BES).

4.2.5.4 Protection Systems and Sudden Pressure Relaying for station service or excitation transformers connected to the generator bus of generators which are part of the BES, that act to trip the generator either directly or via lockout or tripping auxiliary relays.

4.2.6 Automatic Reclosing[1], including:

4.2.6.1 Automatic Reclosing applied on the terminals of Elements connected to the BES bus located at generating plant substations where the total installed gross generating plant capacity is greater than the gross capacity of the largest BES generating unit within the Balancing Authority Area or, if a member of a Reserve Sharing Group, the largest generating unit within the Reserve Sharing Group. ~~.~~[2]

4.2.6.2 Automatic Reclosing applied on the terminals of all BES Elements at substations one bus away from generating plants specified in Section 4.2.6.1 when the substation is less than 10 circuit-miles from the generating plant substation.

4.2.6.3. Automatic Reclosing applied as an integral part of an RAS~~SPS~~ specified in Section 4.2.4.

5. **Effective Date:** See Implementation Plan

6. **Definitions Used in this Standard:**

Automatic Reclosing – Includes the following Components:

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[1] Automatic Reclosing addressed in Section 4.2.6.1 and 4.2.6.2 may be excluded if the equipment owner can demonstrate that a close-in three-phase fault present for twice the normal clearing time (capturing a minimum trip-close-trip time delay) does not result in a total loss of gross generation in the Interconnection exceeding the gross capacity of the largest relevant BES generating unit ~~within the Balancing Authority Area the~~ where the Automatic Reclosing is applied.

[2] The largest BES generating unit within the Balancing Authority Area or the largest generating unit within the Reserve Sharing Group, as applicable, is subject to change. As a result of such a change, the Automatic Reclosing Components subject to the standard could change effective on the date of such change.

- Reclosing relay
- Control circuitry associated with the reclosing relay.

Sudden Pressure Relaying – A system that trips an interrupting device(s) to isolate the equipment it is monitoring and includes the following Components:

- Fault pressure relay – a mechanical relay or device that detects rapid changes in gas pressure, oil pressure, or oil flow that are indicative of Faults within liquid-filled, wire-wound equipment
- Control circuitry associated with a fault pressure relay

Unresolved Maintenance Issue – A deficiency identified during a maintenance activity that causes the Component to not meet the intended performance, cannot be corrected during the maintenance interval, and requires follow-up corrective action.

Segment – Components of a consistent design standard, or a particular model or type from a single manufacturer that typically share other common elements. Consistent performance is expected across the entire population of a Segment. A Segment must contain at least sixty (60) individual Components.

Component Type –

- Any one of the five specific elements of a Protection System.
- Any one of the two specific elements of Automatic Reclosing.
- Any one of the two specific elements of Sudden Pressure Relaying.

Rationale for the deletion of part of the definition of Component: The SDT determined that it was explanatory in nature and adequately addressed in the Supplementary Reference and FAQ Document.

Component – Any individual discrete piece of equipment included in a Protection System, Automatic Reclosing, or Sudden Pressure Relaying.

Countable Event – A failure of a Component requiring repair or replacement, any condition discovered during the maintenance activities in Tables 1-1 through 1-5, Table 3, Tables 4-1 through 4-2, and Table 5, which requires corrective action or a Protection System Misoperation attributed to hardware failure or calibration failure. Misoperations due to product design errors, software errors, relay settings different from specified settings, Protection System Component, Automatic Reclosing, or Sudden Pressure Relaying configuration or application errors are not included in Countable Events.

B. Requirements and Measures

R1. Each Transmission Owner, Generator Owner, and Distribution Provider shall establish a Protection System Maintenance Program (PSMP) for its Protection Systems, Automatic Reclosing, and Sudden Pressure Relaying identified in Section 4.2, Facilities. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning*]

The PSMP shall:

1.1. Identify which maintenance method (time-based, performance-based per PRC-005 Attachment A, or a combination) is used to address each Protection System, Automatic Reclosing, and Sudden Pressure Relaying Component Type. All batteries associated with the station dc supply Component Type of a Protection System shall be included in a time-based program as described in Table 1-4 and Table 3.

1.2. Include the applicable monitored Component attributes applied to each Protection System, Automatic Reclosing, and Sudden Pressure Relaying Component Type consistent with the maintenance intervals specified in Tables 1-1 through 1-5, Table 2, Table 3, Table 4-1 through 4-2, and Table 5 where monitoring is used to extend the maintenance intervals beyond those specified for unmonitored Protection System, Automatic Reclosing, and Sudden Pressure Relaying Components.

M1. Each Transmission Owner, Generator Owner and Distribution Provider shall have a documented Protection System Maintenance Program in accordance with Requirement R1.

For each Protection System, Automatic Reclosing, and Sudden Pressure Relaying Component Type, the documentation shall include the type of maintenance method applied (time-based, performance-based, or a combination of these maintenance methods), and shall include all batteries associated with the station dc supply Component Types in a time-based program as described in Table 1-4 and Table 3. (Part 1.1)

For Component Types that use monitoring to extend the maintenance intervals, the responsible entity(s) shall have evidence for each Protection System, Automatic Reclosing, and Sudden Pressure Relaying Component Type (such as manufacturer's specifications or engineering drawings) of the appropriate monitored Component attributes as specified in Tables 1-1 through 1-5, Table 2, Table 3, Table 4-1 through 4-2, and Table 5. (Part 1.2)

R2. Each Transmission Owner, Generator Owner, and Distribution Provider that uses performance-based maintenance intervals in its PSMP shall follow the procedure established in PRC-005 Attachment A to establish and maintain its performance-based intervals. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

M2. Each Transmission Owner, Generator Owner, and Distribution Provider that uses performance-based maintenance intervals shall have evidence that its current performance-based maintenance program(s) is in accordance with Requirement R2, which may include, but is not limited to, Component lists, dated maintenance records, and dated analysis records and results.

Rationale for R3 **Part 3.1:** In the last posting, the SDT included language in the standard that was originally in the implementation plan that required completion of maintenance activities within three years for newly-identified Automatic Reclosing Components following a notification under Requirement R6, which has been removed. After further discussion, the SDT determined that a separate shorter timeframe for maintenance of newly-identified Automatic Reclosing Components created unnecessary complication within the standard. The SDT agreed that entities should be responsible for maintaining the Automatic Reclosing Components subject to the standard, whether existing, newly added or newly within scope based on a change in the largest generating unit in the BA or, if a member of a Reserve Sharing Group, the largest generating unit within the Reserve Sharing Group according to the timeframes in the maintenance tables. Therefore, 3.1 and its subparts have been removed and have not been reinserted into the implementation plan. ~~The SDT, upon further reflection, determined that the PRC-005-3 Implementation Plan actually included a requirement that entities with newly-identified Automatic Reclosing Components implement its PSMP for those Components, and therefore determined that it was more appropriate to include this information in the standard rather than the implementation plan.~~

R3. Each Transmission Owner, Generator Owner, and Distribution Provider that utilizes time-based maintenance program(s) shall~~, except as provided in part 3.1,~~ maintain its Protection System, Automatic Reclosing, and Sudden Pressure Relaying Components that are included within the time-based maintenance program in accordance with the minimum maintenance activities and maximum maintenance intervals prescribed within Tables 1-1 through 1-5, Table 2, Table 3, Table 4-1 through 4-2, and Table 5. *[Violation Risk Factor: High] [Time Horizon: Operations Planning]*

~~**3.1.** For each newly-identified Automatic Reclosing Component following a notification under Requirement R6, each Transmission Owner, Generator Owner, and Distribution Provider shall perform maintenance activities or provide documentation of prior maintenance activities according to either 3.1.1 or 3.1.2.~~

~~**3.1.1.** Complete the maintenance activities prescribed within Tables 4-1, 4-2(a), and 4-2(b) for the newly-identified Automatic Reclosing Component prior to the end of the third calendar year following the notification under Requirement R6; or~~

~~**3.1.2.** Provide documentation that the Automatic Reclosing Component was last maintained in accordance with the minimum maintenance activities and maximum maintenance intervals prescribed within Tables 4-1, 4-2(a), and 4-2(b).~~

M3. Each Transmission Owner, Generator Owner, and Distribution Provider that utilizes time-based maintenance program(s) shall have evidence that it has maintained its Protection System, Automatic Reclosing, and Sudden Pressure Relaying Components included within its time-based program in accordance with Requirement R3. The evidence may include, but is not limited to, dated maintenance records, dated maintenance summaries, dated check-off lists, dated inspection records, or dated work orders.

Rationale for R4 **Part 4.1:** In the last posting, the SDT included language in the standard that was originally in the implementation plan that required completion of maintenance activities within three years for newly-identified Automatic Reclosing Components following a notification under Requirement R6, which has been removed. After further discussion, the SDT determined that a separate shorter timeframe for maintenance of newly-identified Automatic Reclosing Components created unnecessary complication within the standard. The SDT agreed that entities should be responsible for maintaining the Automatic Reclosing Components subject to the standard, whether existing, newly added or newly within scope based on a change in the largest generating unit in the BA or, if a member of a Reserve Sharing Group, the largest generating unit within the Reserve Sharing Group according to the timeframes in the maintenance tables. Therefore, 4.1 and its subparts have been removed and have not been reinserted into the implementation plan. ~~The SDT, upon further reflection, determined that the PRC-005-3 Implementation Plan actually included a requirement that entities with newly-identified Automatic Reclosing Components implement its PSMP for those Components, and therefore determined that it was more appropriate to include this information in the standard rather than the implementation plan.~~

R4. Each Transmission Owner, Generator Owner, and Distribution Provider that utilizes performance-based maintenance program(s) in accordance with Requirement R2 shall ~~, except as provided in part 4.1,~~ implement and follow its PSMP for its Protection System, Automatic Reclosing, and Sudden Pressure Relaying Components that are included within the performance-based program(s). *[Violation Risk Factor: High] [Time Horizon: Operations Planning]*

~~**4.1.** For each newly-identified Automatic Reclosing Component following a notification under Requirement R6, each Transmission Owner, Generator Owner, and Distribution Provider shall perform maintenance activities or provide documentation of prior maintenance activities according to either 4.1.1 or 4.1.2.~~

~~**4.1.1.** Complete the maintenance activities prescribed within Tables 4-1, 4-2(a), and 4-2(b) for the newly-identified Automatic Reclosing Component prior to the end of the third calendar year following the notification under Requirement R6; or~~

~~**4.1.2.** Provide documentation that the Automatic Reclosing Component was last maintained in accordance with the minimum maintenance activities and maximum maintenance intervals prescribed within Tables 4-1, 4-2(a), and 4-2(b).~~

M4. Each Transmission Owner, Generator Owner, and Distribution Provider that utilizes performance-based maintenance intervals in accordance with Requirement R2 shall have evidence that it has implemented the Protection System Maintenance Program for the Protection System, Automatic Reclosing, and Sudden Pressure Relaying Components included in its performance-based program in accordance with Requirement R4. The evidence may include, but is not limited to, dated maintenance records, dated maintenance summaries, dated check-off lists, dated inspection records, or dated work orders.

R5. Each Transmission Owner, Generator Owner, and Distribution Provider shall demonstrate efforts to correct identified Unresolved Maintenance Issues. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

M5. Each Transmission Owner, Generator Owner, and Distribution Provider shall have evidence that it has undertaken efforts to correct identified Unresolved Maintenance Issues in accordance with Requirement R5. The evidence may include, but is not limited to, work orders, replacement Component orders, invoices, project schedules with completed milestones, return material authorizations (RMAs) or purchase orders.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

As defined in the NERC Rules of Procedure, "Compliance Enforcement Authority" means NERC or the Regional Entity in their respective roles of monitoring and enforcing compliance with the NERC Reliability Standards.

1.2. Evidence Retention

The following evidence retention periods identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

The Transmission Owner, Generator Owner, and Distribution Provider~~, and Balancing Authority~~ shall each keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

For Requirement R1, the Transmission Owner, Generator Owner, and Distribution Provider shall each keep its current dated Protection System Maintenance Program, as well as any superseded versions since the preceding compliance audit, including the documentation that specifies the type of maintenance program applied for each Protection System, Automatic Reclosing, or Sudden Pressure Relaying Component Type.

For Requirement R2, Requirement R3, Requirement R4, and Requirement R5, in cases where the interval of the maintenance activity is longer than the audit cycle, the Transmission Owner, Generator Owner, and Distribution Provider shall each keep documentation of the most recent performance of that~~each distinct~~ maintenance activity for the Protection System, Automatic Reclosing, or Sudden Pressure Relaying Component. In cases where the interval of the maintenance activity is shorter than the audit cycle, documentation of~~, or~~ all performances of that~~each distinct~~ maintenance activity for the Protection System, Automatic Reclosing, or Sudden Pressure Relaying Component since the previous scheduled audit date shall be retained~~, whichever is longer~~.

~~For Requirement R6, the Balancing Authority shall keep documentation for three calendar years that it provided information identifying the largest BES generating unit to the Transmission Owners, Generator Owners, and Distribution Providers in its Balancing Authority Area.~~

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.3. Compliance Monitoring and Assessment Processes:

Compliance Audits

Self-Certifications

Spot Checking

Compliance Violation Investigations

Self-Reporting

Complaints

1.4. Additional Compliance Information

None

Table of Compliance Elements

Requirement Number	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	The entity's PSMP failed to specify whether one Component Type is being addressed by time-based or performance-based maintenance, or a combination of both (Part~~part~~ 1.1).	The entity's PSMP failed to specify whether two Component Types are being addressed by time-based or performance-based maintenance, or a combination of both (Part~~part~~ 1.1).	The entity's PSMP failed to specify whether three Component Types are being addressed by time-based or performance-based maintenance, or a combination of both. (Part~~part~~ 1.1). OR The entity's PSMP failed to include the applicable monitoring attributes applied to each Component Type consistent with the maintenance intervals specified in Tables 1-1 through 1-5, Table 2, Table 3, Tables 4-1 through 4-2, and Table 5 where monitoring is used to extend the maintenance intervals beyond those specified for unmonitored Components (Part~~part~~ 1.2).	The entity failed to establish a PSMP. OR The entity's PSMP failed to specify whether four or more Component Types are being addressed by time-based or performance-based maintenance, or a combination of both (Part~~part~~ 1.1). OR The entity's PSMP failed to include applicable station batteries in a time-based program (Part~~part~~ 1.1).
R2	The entity uses performance-based maintenance intervals in its PSMP but failed to reduce Countable Events to no more than 4% within three years.	NA	The entity uses performance-based maintenance intervals in its PSMP but failed to reduce Countable Events to no more than 4% within four years.	The entity uses performance-based maintenance intervals in its PSMP but: 1) Failed to establish the technical justification described within Requirement R2 for the initial use of the performance-based PSMP OR 2) Failed to reduce Countable Events to no more than 4% within five years OR

Requirement Number	Lower VSL	Moderate VSL	High VSL	Severe VSL
				3) Maintained a Segment with less than 60 Components OR 4) Failed to: • Annually update the list of Components, OR • Annually perform maintenance on the greater of 5% of the Segment population or 3 Components, OR • Annually analyze the program activities and results for each Segment.
R3	For Components included within a time-based maintenance program, the entity failed to maintain 5% or less of the total Components included within a specific Component Type in accordance with the minimum maintenance activities and maximum maintenance intervals prescribed within Tables 1-1 through 1-5, Table 2, Table 3, Tables 4-1 through 4-2, and Table 5. ~~For Automatic Reclosing Components added to a time-based maintenance program per information from the Balancing~~	For Components included within a time-based maintenance program, the entity failed to maintain more than 5% but 10% or less of the total Components included within a specific Component Type in accordance with the minimum maintenance activities and maximum maintenance intervals prescribed within Tables 1-1 through 1-5, Table 2, Table 3, Tables 4-1 through 4-2, and Table 5. ~~For Automatic Reclosing Components added to a time-based maintenance program per~~	For Components included within a time-based maintenance program, the entity failed to maintain more than 10% but 15% or less of the total Components included within a specific Component Type in accordance with the minimum maintenance activities and maximum maintenance intervals prescribed within Tables 1-1 through 1-5, Table 2, Table 3, Tables 4-1 through 4-2, and Table 5. ~~For Automatic Reclosing Components added to a time-based maintenance program per~~	For Components included within a time-based maintenance program, the entity failed to maintain more than 15% of the total Components included within a specific Component Type in accordance with the minimum maintenance activities and maximum maintenance intervals prescribed within Tables 1-1 through 1-5, Table 2, Table 3, Tables 4-1 through 4-2, and Table 5. ~~For Automatic Reclosing Components added to a time-~~

Requirement Number	Lower VSL	Moderate VSL	High VSL	Severe VSL
	~~Authority, the entity failed to maintain 5% or less of the total Components in accordance with the minimum maintenance activities and maximum maintenance intervals prescribed within Tables 4-1 through 4-2.~~	~~information from the Balancing Authority, the entity failed to maintain more than 5% but 10% or less of the total Components in accordance with the minimum maintenance activities and maximum maintenance intervals prescribed within Tables 4-1 through 4-2.~~	~~information from the Balancing Authority, the entity failed to maintain more than 10% but 15% or less of the total Components in accordance with the minimum maintenance activities and maximum maintenance intervals prescribed within Tables 4-1 through 4-2.~~	~~based maintenance program per information from the Balancing Authority, the entity failed to maintain more than 15% of the total Components in accordance with the minimum maintenance activities and maximum maintenance intervals prescribed within Tables 4-1 through 4-2.~~
R4	For Components included within a performance-based maintenance program, the entity failed to maintain 5% or less of the annual scheduled maintenance for a specific Component Type in accordance with their performance-based PSMP. ~~For Automatic Reclosing Components added to a performance-based maintenance program per information from the Balancing Authority, the entity failed to maintain 5% or less of the total Components in accordance with their performance-based PSMP.~~	For Components included within a performance-based maintenance program, the entity failed to maintain more than 5% but 10% or less of the annual scheduled maintenance for a specific Component Type in accordance with their performance-based PSMP. ~~For Automatic Reclosing Components added to a performance-based maintenance program per information from the Balancing Authority, the entity failed to maintain more than 5% but 10% or less of the total Components in accordance with their performance-based PSMP.~~	For Components included within a performance-based maintenance program, the entity failed to maintain more than 10% but 15% or less of the annual scheduled maintenance for a specific Component Type in accordance with their performance-based PSMP. ~~For Automatic Reclosing Components added to a performance-based maintenance program per information from the Balancing Authority, the entity failed to maintain more than 10% but 15% or less of the total Components in accordance with their performance-based PSMP.~~	For Components included within a performance-based maintenance program, the entity failed to maintain more than 15% of the annual scheduled maintenance for a specific Component Type in accordance with their performance-based PSMP. ~~For Automatic Reclosing Components added to a performance-based maintenance program per information from the Balancing Authority, the entity failed to maintain more than 15% of the total Components in accordance with their performance-based PSMP.~~

Requirement Number	Lower VSL	Moderate VSL	High VSL	Severe VSL
R5	The entity failed to undertake efforts to correct 5 or fewer identified Unresolved Maintenance Issues.	The entity failed to undertake efforts to correct greater than 5 but less than or equal to 10 identified Unresolved Maintenance Issues.	The entity failed to undertake efforts to correct greater than 10 but less than or equal to 15 identified Unresolved Maintenance Issues.	The entity failed to undertake efforts to correct greater than 15 identified Unresolved Maintenance Issues.
~~R6~~				~~The entity failed to notify each Transmission Owner, Generator Owner, and Distribution Provider within its Balancing Authority Area at least once every calendar year of the gross capacity, in MW or MVA, of the largest BES generating unit within the Balancing Authority Area.~~ ~~OR~~ ~~The entity had more than 15 calendar months between notifications to each Transmission Owner, Generator Owner, and Distribution Provider of the gross capacity, in MW or MVA, of the largest BES generating unit within the Balancing Authority Area.~~

D. Regional Variances

None.

E. Interpretations

None.

F. Supplemental Reference Documents

The following documents present a detailed discussion about determination of maintenance intervals and other useful information regarding establishment of a maintenance program.

1. *Supplementary Reference and FAQ - PRC-005-X Protection System Maintenance,* Protection System Maintenance and Testing Standard Drafting Team (April 2014)
2. *Considerations for Maintenance and Testing of Auto-reclosing Schemes*, NERC System Analysis and Modeling Subcommittee, and NERC System Protection and Control Subcommittee (November 2012)
3. *Sudden Pressure Relays and Other Devices that Respond to Non-Electrical Quantities – SPCS Input for Standard Development in Response to FERC Order No. 758,* NERC System Protection and Control Subcommittee (December 2013)

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
1	December 1, 2005	1. Changed incorrect use of certain hyphens (-) to “en dash” (–) and “em dash (—).” 2. Added “periods” to items where appropriate. 3. Changed “Timeframe” to “Time Frame” in item D, 1.2.	01/20/05
1a	February 17, 2011	Added Appendix 1 - Interpretation regarding applicability of standard to protection of radially connected transformers	Project 2009-17 interpretation
1a	February 17, 2011	Adopted by Board of Trustees	

1a	September 26, 2011	FERC Order issued approving interpretation of R1 and R2 (FERC's Order is effective as of September 26, 2011)	
1.1a	February 1, 2012	Errata change: Clarified inclusion of generator interconnection Facility in Generator Owner's responsibility	Revision under Project 2010-07
1b	February 3, 2012	FERC Order issued approving interpretation of R1, R1.1, and R1.2 (FERC's Order dated March 14, 2012). Updated version from 1a to 1b.	Project 2009-10 Interpretation
1.1b	April 23, 2012	Updated standard version to 1.1b to reflect FERC approval of PRC-005-1b.	Revision under Project 2010-07

1.1b	May 9, 2012	PRC-005-1.1b was adopted by the Board of Trustees as part of Project 2010-07 (Generator Requirements at the Transmission Interface).	
2	November 7, 2012	Adopted by Board of Trustees	Project 2007-17 - Complete revision, absorbing maintenance requirements from PRC-005-1.1b, PRC-008-0, PRC-011-0, PRC-017-0
2	October 17, 2013	Errata Change: The Standards Committee approved an errata change to the implementation plan for PRC-005-2 to add the phrase "or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities;" to the second sentence under the "Retirement of Existing	
3	November 7, 2013	Adopted by the NERC Board of Trustees	Revised to address the FERC directive in Order No.758 to include Automatic Reclosing in maintenance programs.
3.1	February 12, 2014	Approved by the Standards Committee	Errata changes to correct capitalization of defined terms
X			Project 2007-17.3 – Revised to address the FERC directive in Order No. 758 to include sudden pressure relays in maintenance programs.

<table>
<tr><th colspan="3">Table 1-1
Component Type - Protective Relay
Excluding distributed UFLS and distributed UVLS (see Table 3)</th></tr>
<tr><th>Component Attributes</th><th>Maximum Maintenance Interval[3]</th><th>Maintenance Activities</th></tr>
<tr><td>Any unmonitored protective relay not having all the monitoring attributes of a category below.</td><td>6 Calendar Years</td><td>For all unmonitored relays:
• Verify that settings are as specified
For non-microprocessor relays:
• Test and, if necessary calibrate
For microprocessor relays:
• Verify operation of the relay inputs and outputs that are essential to proper functioning of the Protection System.
• Verify acceptable measurement of power system input values.</td></tr>
<tr><td>Monitored microprocessor protective relay with the following:
• Internal self-diagnosis and alarming (see Table 2).
• Voltage and/or current waveform sampling three or more times per power cycle, and conversion of samples to numeric values for measurement calculations by microprocessor electronics.
• Alarming for power supply failure (see Table 2).</td><td>12 Calendar Years</td><td>Verify:
• Settings are as specified.
• Operation of the relay inputs and outputs that are essential to proper functioning of the Protection System.
• Acceptable measurement of power system input values.</td></tr>
</table>

[3] For the tables in this standard, a calendar year starts on the first day of a new year (January 1) after a maintenance activity has been completed.
For the tables in this standard, a calendar month starts on the first day of the first month after a maintenance activity has been completed.

Monitored microprocessor protective relay with preceding row attributes and the following: • Ac measurements are continuously verified by comparison to an independent ac measurement source, with alarming for excessive error (See Table 2). • Some or all binary or status inputs and control outputs are monitored by a process that continuously demonstrates ability to perform as designed, with alarming for failure (See Table 2). • Alarming for change of settings (See Table 2).	12 Calendar Years	Verify only the unmonitored relay inputs and outputs that are essential to proper functioning of the Protection System.

<table>
<tr><th colspan="3">Table 1-2
Component Type - Communications Systems
Excluding distributed UFLS and distributed UVLS (see Table 3)</th></tr>
<tr><th>Component Attributes</th><th>Maximum Maintenance Interval</th><th>Maintenance Activities</th></tr>
<tr><td rowspan="2">Any unmonitored communications system necessary for correct operation of protective functions, and not having all the monitoring attributes of a category below.</td><td>4 Calendar Months</td><td>Verify that the communications system is functional.</td></tr>
<tr><td>6 Calendar Years</td><td>Verify that the communications system meets performance criteria pertinent to the communications technology applied (e.g. signal level, reflected power, or data error rate).
Verify operation of communications system inputs and outputs that are essential to proper functioning of the Protection System.</td></tr>
<tr><td>Any communications system with continuous monitoring or periodic automated testing for the presence of the channel function, and alarming for loss of function (See Table 2).</td><td>12 Calendar Years</td><td>Verify that the communications system meets performance criteria pertinent to the communications technology applied (e.g. signal level, reflected power, or data error rate).
Verify operation of communications system inputs and outputs that are essential to proper functioning of the Protection System.</td></tr>
<tr><td>Any communications system with all of the following:
• Continuous monitoring or periodic automated testing for the performance of the channel using criteria pertinent to the communications technology applied (e.g. signal level, reflected power, or data error rate, and alarming for excessive performance degradation). (See Table 2)
• Some or all binary or status inputs and control outputs are monitored by a process that continuously demonstrates ability to perform as designed, with alarming for failure (See Table 2).</td><td>12 Calendar Years</td><td>Verify only the unmonitored communications system inputs and outputs that are essential to proper functioning of the Protection System</td></tr>
</table>

Table 1-3 Component Type - Voltage and Current Sensing Devices Providing Inputs to Protective Relays Excluding distributed UFLS and distributed UVLS (see Table 3)		
Component Attributes	**Maximum Maintenance Interval**	**Maintenance Activities**
Any voltage and current sensing devices not having monitoring attributes of the category below.	12 Calendar Years	Verify that current and voltage signal values are provided to the protective relays.
Voltage and Current Sensing devices connected to microprocessor relays with AC measurements are continuously verified by comparison of sensing input value, as measured by the microprocessor relay, to an independent ac measurement source, with alarming for unacceptable error or failure (see Table 2).	No periodic maintenance specified	None.

Table 1-4(a)

Component Type – Protection System Station dc Supply Using Vented Lead-Acid (VLA) Batteries

Excluding distributed UFLS and distributed UVLS (see Table 3)

Protection System Station dc supply used only for non-BES interrupting devices for RAS~~SPS~~, non-distributed UFLS systems, or non-distributed UVLS systems is excluded (see Table 1-4(e)).

Component Attributes	Maximum Maintenance Interval	Maintenance Activities
Protection System Station dc supply using **Vented Lead-Acid (VLA) batteries** not having monitoring attributes of Table 1-4(f).	4 Calendar Months	Verify: • Station dc supply voltage Inspect: • Electrolyte level • For unintentional grounds
	18 Calendar Months	Verify: • Float voltage of battery charger • Battery continuity • Battery terminal connection resistance • Battery intercell or unit-to-unit connection resistance Inspect: • Cell condition of all individual battery cells where cells are visible – or measure battery cell/unit internal ohmic values where the cells are not visible • Physical condition of battery rack

Table 1-4(a) Component Type – Protection System Station dc Supply Using Vented Lead-Acid (VLA) Batteries Excluding distributed UFLS and distributed UVLS (see Table 3) Protection System Station dc supply used only for non-BES interrupting devices for RAS~~SPS~~, non-distributed UFLS systems, or non-distributed UVLS systems is excluded (see Table 1-4(e)).		
Component Attributes	**Maximum Maintenance Interval**	**Maintenance Activities**
	18 Calendar Months -or- 6 Calendar Years	Verify that the station battery can perform as manufactured by evaluating cell/unit measurements indicative of battery performance (e.g. internal ohmic values or float current) against the station battery baseline. -or- Verify that the station battery can perform as manufactured by conducting a performance or modified performance capacity test of the entire battery bank.

Table 1-4(b) Component Type – Protection System Station dc Supply Using Valve-Regulated Lead-Acid (VRLA) Batteries Excluding distributed UFLS and distributed UVLS (see Table 3) Protection System Station dc supply used only for non-BES interrupting devices for RAS~~SPS~~, non-distributed UFLS systems, or non-distributed UVLS systems is excluded (see Table 1-4(e)).		
Component Attributes	**Maximum Maintenance Interval**	**Maintenance Activities**
Protection System Station dc supply **with Valve Regulated Lead-Acid (VRLA) batteries** not having monitoring attributes of Table 1-4(f).	4 Calendar Months	Verify: • Station dc supply voltage Inspect: • For unintentional grounds
	6 Calendar Months	Inspect: • Condition of all individual units by measuring battery cell/unit internal ohmic values.
	18 Calendar Months	Verify: • Float voltage of battery charger • Battery continuity • Battery terminal connection resistance • Battery intercell or unit-to-unit connection resistance Inspect: • Physical condition of battery rack

Table 1-4(b) Component Type – Protection System Station dc Supply Using Valve-Regulated Lead-Acid (VRLA) Batteries Excluding distributed UFLS and distributed UVLS (see Table 3) Protection System Station dc supply used only for non-BES interrupting devices for RAS~~SPS~~, non-distributed UFLS systems, or non-distributed UVLS systems is excluded (see Table 1-4(e)).		
Component Attributes	**Maximum Maintenance Interval**	**Maintenance Activities**
	6 Calendar Months -or- 3 Calendar Years	Verify that the station battery can perform as manufactured by evaluating cell/unit measurements indicative of battery performance (e.g. internal ohmic values or float current) against the station battery baseline. -or- Verify that the station battery can perform as manufactured by conducting a performance or modified performance capacity test of the entire battery bank.

Table 1-4(c)

Component Type – Protection System Station dc Supply Using Nickel-Cadmium (NiCad) Batteries

Excluding distributed UFLS and distributed UVLS (see Table 3)

Protection System Station dc supply used only for non-BES interrupting devices for RAS~~SPS~~, non-distributed UFLS system, or non-distributed UVLS systems is excluded (see Table 1-4(e)).

Component Attributes	Maximum Maintenance Interval	Maintenance Activities
Protection System Station dc supply **Nickel-Cadmium (NiCad) batteries** not having monitoring attributes of Table 1-4(f).	4 Calendar Months	Verify: • Station dc supply voltage Inspect: • Electrolyte level • For unintentional grounds
	18 Calendar Months	Verify: • Float voltage of battery charger • Battery continuity • Battery terminal connection resistance • Battery intercell or unit-to-unit connection resistance Inspect: • Cell condition of all individual battery cells. • Physical condition of battery rack

Table 1-4(c)

Component Type – Protection System Station dc Supply Using Nickel-Cadmium (NiCad) Batteries

Excluding distributed UFLS and distributed UVLS (see Table 3)

Protection System Station dc supply used only for non-BES interrupting devices for RAS~~SPS~~, non-distributed UFLS system, or non-distributed UVLS systems is excluded (see Table 1-4(e)).

Component Attributes	Maximum Maintenance Interval	Maintenance Activities
	6 Calendar Years	Verify that the station battery can perform as manufactured by conducting a performance or modified performance capacity test of the entire battery bank.

Table 1-4(d) Component Type – Protection System Station dc Supply Using Non Battery Based Energy Storage Excluding distributed UFLS and distributed UVLS (see Table 3) Protection System Station dc supply used only for non-BES interrupting devices for RAS~~SPS~~, non-distributed UFLS system, or non-distributed UVLS systems is excluded (see Table 1-4(e)).		
Component Attributes	**Maximum Maintenance Interval**	**Maintenance Activities**
Any Protection System station dc supply not using a battery and not having monitoring attributes of Table 1-4(f).	4 Calendar Months	Verify: • Station dc supply voltage Inspect: • For unintentional grounds
	18 Calendar Months	Inspect: Condition of non-battery based dc supply
	6 Calendar Years	Verify that the dc supply can perform as manufactured when ac power is not present.

Table 1-4(e) Component Type – Protection System Station dc Supply for non-BES Interrupting Devices for RAS~~SPS~~, non-distributed UFLS, and non-distributed UVLS systems		
Component Attributes	**Maximum Maintenance Interval**	**Maintenance Activities**
Any Protection System dc supply used for tripping only non-BES interrupting devices as part of a ~~SPS~~RAS, non-distributed UFLS, or non-distributed UVLS system and not having monitoring attributes of Table 1-4(f).	When control circuits are verified (See Table 1-5)	Verify Station dc supply voltage.

Table 1-4(f) Exclusions for Protection System Station dc Supply Monitoring Devices and Systems		
Component Attributes	**Maximum Maintenance Interval**	**Maintenance Activities**
Any station dc supply with high and low voltage monitoring and alarming of the battery charger voltage to detect charger overvoltage and charger failure (See Table 2).	No periodic maintenance specified	No periodic verification of station dc supply voltage is required.
Any battery based station dc supply with electrolyte level monitoring and alarming in every cell (See Table 2).		No periodic inspection of the electrolyte level for each cell is required.
Any station dc supply with unintentional dc ground monitoring and alarming (See Table 2).		No periodic inspection of unintentional dc grounds is required.
Any station dc supply with charger float voltage monitoring and alarming to ensure correct float voltage is being applied on the station dc supply (See Table 2).		No periodic verification of float voltage of battery charger is required.
Any battery based station dc supply with monitoring and alarming of battery string continuity (See Table 2).		No periodic verification of the battery continuity is required.
Any battery based station dc supply with monitoring and alarming of the intercell and/or terminal connection detail resistance of the entire battery (See Table 2).		No periodic verification of the intercell and terminal connection resistance is required.
Any Valve Regulated Lead-Acid (VRLA) or Vented Lead-Acid (VLA) station battery with internal ohmic value or float current monitoring and alarming, and evaluating present values relative to baseline internal ohmic values for every cell/unit (See Table 2).		No periodic evaluation relative to baseline of battery cell/unit measurements indicative of battery performance is required to verify the station battery can perform as manufactured.
Any Valve Regulated Lead-Acid (VRLA) or Vented Lead-Acid (VLA) station battery with monitoring and alarming of each cell/unit internal ohmic value (See Table 2).		No periodic inspection of the condition of all individual units by measuring battery cell/unit internal ohmic values of a station VRLA or Vented Lead-Acid (VLA) battery is required.

Table 1-5 **Component Type - Control Circuitry Associated With Protective Functions** **Excluding distributed UFLS and distributed UVLS (see Table 3), Automatic Reclosing (see Table 4), and Sudden Pressure Relaying (see Table 5)** **Note: Table requirements apply to all Control Circuitry Components of Protection Systems, and RAS~~SPSs~~ except as noted.**		
Component Attributes	**Maximum Maintenance Interval**	**Maintenance Activities**
Trip coils or actuators of circuit breakers, interrupting devices, or mitigating devices (regardless of any monitoring of the control circuitry).	6 Calendar Years	Verify that each trip coil is able to operate the circuit breaker, interrupting device, or mitigating device.
Electromechanical lockout devices which are directly in a trip path from the protective relay to the interrupting device trip coil (regardless of any monitoring of the control circuitry).	6 Calendar Years	Verify electrical operation of electromechanical lockout devices.
Unmonitored control circuitry associated with ~~SPS~~RAS. (See Table 4-2(b) for ~~SPS~~ RAS which include Automatic Reclosing.)	12 Calendar Years	Verify all paths of the control circuits essential for proper operation of the ~~SPS~~RAS.
Unmonitored control circuitry associated with protective functions inclusive of all auxiliary relays.	12 Calendar Years	Verify all paths of the trip circuits inclusive of all auxiliary relays through the trip coil(s) of the circuit breakers or other interrupting devices.
Control circuitry associated with protective functions and/or ~~SPSs~~ RAS whose integrity is monitored and alarmed (See Table 2).	No periodic maintenance specified	None.

Table 2 – Alarming Paths and Monitoring In Tables 1-1 through 1-5, Table 3, ~~and~~ Tables 4-1 through 4-2, and Table 5 alarm attributes used to justify extended maximum maintenance intervals and/or reduced maintenance activities are subject to the following maintenance requirements		
Component Attributes	**Maximum Maintenance Interval**	**Maintenance Activities**
Any alarm path through which alarms in Tables 1-1 through 1-5, Table 3, ~~and~~ Tables 4-1 through 4-2, and Table 5 are conveyed from the alarm origin to the location where corrective action can be initiated, and not having all the attributes of the "Alarm Path with monitoring" category below. Alarms are reported within 24 hours of detection to a location where corrective action can be initiated.	12 Calendar Years	Verify that the alarm path conveys alarm signals to a location where corrective action can be initiated.
Alarm Path with monitoring: The location where corrective action is taken receives an alarm within 24 hours for failure of any portion of the alarming path from the alarm origin to the location where corrective action can be initiated.	No periodic maintenance specified	None.

Table 3 Maintenance Activities and Intervals for distributed UFLS and distributed UVLS Systems		
Component Attributes	**Maximum Maintenance Interval**	**Maintenance Activities**
Any unmonitored protective relay not having all the monitoring attributes of a category below.	6 Calendar Years	Verify that settings are as specified. For non-microprocessor relays: • Test and, if necessary calibrate. For microprocessor relays: • Verify operation of the relay inputs and outputs that are essential to proper functioning of the Protection System. • Verify acceptable measurement of power system input values.
Monitored microprocessor protective relay with the following: • Internal self-diagnosis and alarming (See Table 2). • Voltage and/or current waveform sampling three or more times per power cycle, and conversion of samples to numeric values for measurement calculations by microprocessor electronics. Alarming for power supply failure (See Table 2).	12 Calendar Years	Verify: • Settings are as specified. • Operation of the relay inputs and outputs that are essential to proper functioning of the Protection System. • Acceptable measurement of power system input values
Monitored microprocessor protective relay with preceding row attributes and the following: • Ac measurements are continuously verified by comparison to an independent ac measurement source, with alarming for excessive error (See Table 2).	12 Calendar Years	Verify only the unmonitored relay inputs and outputs that are essential to proper functioning of the Protection System.

Table 3 Maintenance Activities and Intervals for distributed UFLS and distributed UVLS Systems		
Component Attributes	**Maximum Maintenance Interval**	**Maintenance Activities**
• Some or all binary or status inputs and control outputs are monitored by a process that continuously demonstrates ability to perform as designed, with alarming for failure (See Table 2). Alarming for change of settings (See Table 2).		
Voltage and/or current sensing devices associated with UFLS or UVLS systems.	12 Calendar Years	Verify that current and/or voltage signal values are provided to the protective relays.
Protection System dc supply for tripping non-BES interrupting devices used only for a UFLS or UVLS system.	12 Calendar Years	Verify Protection System dc supply voltage.
Control circuitry between the UFLS or UVLS relays and electromechanical lockout and/or tripping auxiliary devices (excludes non-BES interrupting device trip coils).	12 Calendar Years	Verify the path from the relay to the lockout and/or tripping auxiliary relay (including essential supervisory logic).
Electromechanical lockout and/or tripping auxiliary devices associated only with UFLS or UVLS systems (excludes non-BES interrupting device trip coils).	12 Calendar Years	Verify electrical operation of electromechanical lockout and/or tripping auxiliary devices.
Control circuitry between the electromechanical lockout and/or tripping auxiliary devices and the non-BES interrupting devices in UFLS or UVLS systems, or between UFLS or UVLS relays (with no interposing electromechanical lockout or auxiliary device) and the non-BES interrupting devices (excludes non-BES interrupting device trip coils).	No periodic maintenance specified	None.
Trip coils of non-BES interrupting devices in UFLS or UVLS systems.	No periodic maintenance specified	None.

Table 4-1 Maintenance Activities and Intervals for Automatic Reclosing Components Component Type – Reclosing Relay		
Component Attributes	**Maximum Maintenance Interval**	**Maintenance Activities**
Any unmonitored reclosing relay not having all the monitoring attributes of a category below.	6 Calendar Years	Verify that settings are as specified. For non-microprocessor relays: • Test and, if necessary calibrate For microprocessor relays: • Verify operation of the relay inputs and outputs that are essential to proper functioning of the Automatic Reclosing.
Monitored microprocessor reclosing relay with the following: • Internal self-diagnosis and alarming (See Table 2). • Alarming for power supply failure (See Table 2).	12 Calendar Years	Verify: • Settings are as specified. • Operation of the relay inputs and outputs that are essential to proper functioning of the Automatic Reclosing.

Table 4-2(a) Maintenance Activities and Intervals for Automatic Reclosing Components Component Type – Control Circuitry Associated with Reclosing Relays that are NOT an Integral Part of an RAS~~SPS~~		
Component Attributes	**Maximum Maintenance Interval**	**Maintenance Activities**
Unmonitored Control circuitry associated with Automatic Reclosing that is not an integral part of an ~~SPS~~RAS.	12 Calendar Years	Verify that Automatic Reclosing, upon initiation, does not issue a premature closing command to the close circuitry.
Control circuitry associated with Automatic Reclosing that is not part of an ~~SPS~~ RAS and is monitored and alarmed for conditions that would result in a premature closing command. (See Table 2)	No periodic maintenance specified	None.

Table 4-2(b) Maintenance Activities and Intervals for Automatic Reclosing Components Component Type – Control Circuitry Associated with Reclosing Relays that ARE an Integral Part of an RAS~~SPS~~		
Component Attributes	**Maximum Maintenance Interval**	**Maintenance Activities**
Close coils or actuators of circuit breakers or similar devices that are used in conjunction with Automatic Reclosing as part of an ~~SPS~~ RAS (regardless of any monitoring of the control circuitry).	6 Calendar Years	Verify that each close coil or actuator is able to operate the circuit breaker or mitigating device.
Unmonitored close control circuitry associated with Automatic Reclosing used as an integral part of an ~~SPS~~RAS.	12 Calendar Years	Verify all paths of the control circuits associated with Automatic Reclosing that are essential for proper operation of the ~~SPS~~RAS.
Control circuitry associated with Automatic Reclosing that is an integral part of an ~~SPS~~ RAS whose integrity is monitored and alarmed. (See Table 2)	No periodic maintenance specified	None.

Table 5 Maintenance Activities and Intervals for Sudden Pressure Relaying ~~Note: In cases where Components of Sudden Pressure Relaying are common to Components listed in Table 1-5, the Components only need to be tested once during a distinct maintenance interval.~~		
Component Attributes	**Maximum Maintenance Interval**	**Maintenance Activities**
Any fault pressure relay.	6 Calendar Years	Verify the pressure or flow sensing mechanism is operable.
Electromechanical lockout devices which are directly in a trip path from the fault pressure relay to the interrupting device trip coil (regardless of any monitoring of the control circuitry).	6 Calendar Years	Verify electrical operation of electromechanical lockout devices.
Control circuitry associated with Sudden Pressure Relaying. ~~from the fault pressure relay to the interrupting device trip coil(s).~~	12 Calendar Years	Verify all paths of the trip~~control~~ circuits inclusive~~that are essential for proper operation~~ of all auxiliary relays through the trip coil(s) of the circuit breakers or other interrupting devices~~Sudden Pressure Relaying~~.
Control circuitry associated with Sudden Pressure Relaying whose integrity is monitored and alarmed (See Table 2).	No periodic maintenance specified	None.

PRC-005 — Attachment A

Criteria for a Performance-Based Protection System Maintenance Program

Purpose: To establish a technical basis for initial and continued use of a performance-based Protection System Maintenance Program (PSMP).

To establish the technical justification for the initial use of a performance-based PSMP:

1. Develop a list with a description of Components included in each designated Segment, with a minimum Segment population of 60 Components.
2. Maintain the Components in each Segment according to the time-based maximum allowable intervals established in Tables 1-1 through 1-5, Table 3, Tables 4-1 through 4-2, and Table 5 until results of maintenance activities for the Segment are available for a minimum of 30 individual Components of the Segment.
3. Document the maintenance program activities and results for each Segment, including maintenance dates and Countable Events for each included Component.
4. Analyze the maintenance program activities and results for each Segment to determine the overall performance of the Segment and develop maintenance intervals.
5. Determine the maximum allowable maintenance interval for each Segment such that the Segment experiences Countable Events on no more than 4% of the Components within the Segment, for the greater of either the last 30 Components maintained or all Components maintained in the previous year.

To maintain the technical justification for the ongoing use of a performance-based PSMP:

1. At least annually, update the list of Components and Segments and/or description if any changes occur within the Segment.
2. Perform maintenance on the greater of 5% of the Components (addressed in the performance based PSMP) in each Segment or 3 individual Components within the Segment in each year.
3. For the prior year, analyze the maintenance program activities and results for each Segment to determine the overall performance of the Segment.
4. Using the prior year's data, determine the maximum allowable maintenance interval for each Segment such that the Segment experiences Countable Events on no more than 4% of the Components within the Segment, for the greater of either the last 30 Components maintained or all Components maintained in the previous year.

If the Components in a Segment maintained through a performance-based PSMP experience 4% or more Countable Events, develop, document, and implement an action plan to reduce the Countable Events to less than 4% of the Segment population within 3 years.

Implementation Plan

Protection System, Automatic Reclosing, and Sudden Pressure Relaying Maintenance
PRC-005-X

Standards Involved
Approval:

- PRC-005-X – Protection System, Automatic Reclosing, and Sudden Pressure Relaying Maintenance

Retirement:

- PRC-005-3 – Protection System and Automatic Reclosing Maintenance

Prerequisite Approvals:
N/A

Background:
The Implementation Plan for PRC-005-X addresses Sudden Pressure Relaying, Protection Systems as outlined in PRC-005-2, and Automatic Reclosing Components as outlined in PRC-005-3. PRC-005-X establishes minimum maintenance activities for Sudden Pressure Relaying Component Types and the maximum allowable maintenance intervals for these maintenance activities. PRC-005-X requires entities to revise the Protection System Maintenance Program by now including Sudden Pressure Relaying Components.

The Implementation Plan reflects consideration of the following:

1. The requirements set forth in the proposed standard, which carry forward requirements from PRC-005-2 and PRC-005-3, establish minimum maintenance activities for Protection System, Automatic Reclosing, and Sudden Pressure Relaying Component Types as well as the maximum allowable maintenance intervals for these maintenance activities. The maintenance activities established may not be presently performed by some entities and the established maximum allowable intervals may be shorter than those currently in use by some entities.

2. For entities not presently performing a maintenance activity or using longer intervals than the maximum allowable intervals established in the proposed standard, it is unrealistic for those entities to be immediately compliant with the new activities or intervals. Further, entities should be allowed to become compliant in such a way as to facilitate a continuing maintenance program.

3. Entities that have previously been performing maintenance within the newly specified intervals may not have all the documentation needed to demonstrate compliance with all of the maintenance activities specified.
4. The Implementation Schedule set forth below in this document carries forward the implementation schedules contained in PRC-005-2 and PRC-005-3 and includes changes needed to address the addition of Sudden Pressure Relaying Components in PRC-005-X.
5. The Implementation Schedule set forth in this document facilitates implementation of the more lengthy maintenance intervals within the revised Protection System Maintenance Program in approximately equally-distributed steps over those intervals prescribed for each respective maintenance activity in order that entities may implement this standard in a systematic method that facilitates an effective ongoing Protection System Maintenance Program.

General Considerations:

Each Transmission Owner, Generator Owner, and Distribution Provider shall maintain documentation to demonstrate compliance with PRC-005-1b, PRC-008-0, PRC-011-0, and PRC-017-0 until that entity meets the requirements of PRC-005-2, or the combined successor standards PRC-005-3 and PRC-005-X, in accordance with this implementation plan.

While entities are transitioning from PRC-005-1b, PRC-008-0, PRC-011-0, PRC-017-0, each entity must be prepared to identify:

- All of its applicable Protection System, Automatic Reclosing, and Sudden Pressure Relaying Components, and
- Whether a Component was last maintained according to PRC-005-1b, PRC-008-0, PRC-011-0, PRC-017-0, or a successor PRC-005 standard.

Effective Date

PRC-005-X shall become effective on the first day of the first calendar quarter after the date that the standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first calendar quarter after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

Retirement of Existing Standards:

Standards PRC-005-1b, PRC-008-0, PRC-011-0, and PRC-017-0 shall remain active and applicable to an entity’s Protection System maintenance activities not yet transitioned to PRC-005-2 or a successor standard during transition. Standards PRC-005-1b, PRC-008-0, PRC-011-0, and PRC-017-0 shall be retired at midnight of the day immediately prior to the first day of the first calendar quarter one hundred fifty-six (156) months following applicable regulatory approval of PRC-005-2 or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities; or, in those

jurisdictions where no regulatory approval is required, at midnight of the day immediately prior to the first day of the first calendar quarter one hundred sixty-eight (168) months following the November 2012 NERC Board of Trustees' adoption of PRC-005-2.

PRC-005-2 shall be retired at midnight of the day immediately prior to the first day of the first calendar quarter, twelve (12) calendar months following applicable regulatory approval of PRC-005-3, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities; or, in those jurisdictions where no regulatory approval is required, the first day of the first calendar quarter twelve (12) calendar months from the date of Board of Trustees' adoption.

PRC-005-3 shall be retired at midnight of the day immediately prior to the first day of the first calendar quarter following applicable regulatory approval of PRC-005-X, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities; or, in those jurisdictions where no regulatory approval is required, the first day of the first calendar quarter from the date of Board of Trustees' adoption.

Implementation Plan for Definitions:

This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the Reliability Standards Glossary of Terms (Glossary) are not repeated here. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, the Glossary definition will be removed from the individual standard and added to the Glossary. The definitions of terms used only in the standard will remain in the standard.

Glossary Definition:

Protection System Maintenance Program (PSMP) — An ongoing program by which Protection System, Automatic Reclosing, and Sudden Pressure Relaying Components are kept in working order and proper operation of malfunctioning Components is restored. A maintenance program for a specific Component includes one or more of the following activities:

- Verify — Determine that the Component is functioning correctly.
- Monitor — Observe the routine in-service operation of the Component.
- Test — Apply signals to a Component to observe functional performance or output behavior, or to diagnose problems.
- Inspect — Examine for signs of Component failure, reduced performance or degradation.
- Calibrate — Adjust the operating threshold or measurement accuracy of a measuring element to meet the intended performance requirement.

Definitions of Terms Used in the Standard:

Sudden Pressure Relaying – A system that trips an interrupting device(s) to isolate the equipment it is monitoring and includes the following Components:

- Fault pressure relay – a mechanical relay or device that detects rapid changes in gas pressure, oil pressure, or oil flow that are indicative of Faults within liquid-filled, wire-wound equipment
- Control circuitry associated with a fault pressure relay

Component Type –

- Any one of the five specific elements of a Protection System.
- Any one of the two specific elements of Automatic Reclosing.
- Any one of the two specific elements of Sudden Pressure Relaying.

Component – Any individual discrete piece of equipment included in a Protection System, Automatic Reclosing, or Sudden Pressure Relaying.

Countable Event – A failure of a Component requiring repair or replacement, any condition discovered during the maintenance activities in Tables 1-1 through 1-5, Table 3, Tables 4-1 through 4-2, and Table 5, which requires corrective action or a Protection System Misoperation attributed to hardware failure or calibration failure. Misoperations due to product design errors, software errors, relay settings different from specified settings, Protection System Component, Automatic Reclosing, or Sudden Pressure Relaying configuration or application errors are not included in Countable Events.

Implementation Plan for New or Revised Definitions:

New and revised definitions (Sudden Pressure Relaying, Protection System Maintenance Program, Component Type, Component, and Countable Event) shall become effective after the date that the definitions are approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a definition to go into effect. Where approval by an applicable governmental authority is not required, the definitions shall become effective on the first day of the first calendar quarter after the date the definitions are adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

Implementation Plan for Requirements R1, R2, and R5:

For Protection System Components, entities shall be 100% compliant on the first day of the first calendar quarter twelve (12) months following applicable regulatory approvals of PRC-005-2 or, in those jurisdictions where no regulatory approval is required, on the first day of the first calendar quarter twenty-four (24) months following the November 2012 NERC Board of Trustees' adoption of PRC-005-2 or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

For Automatic Reclosing Components, entities shall be 100% compliant on the first day of the first calendar quarter twelve (12) months following applicable regulatory approvals of PRC-005-3 or, in those jurisdictions where no regulatory approval is required, on the first day of the first calendar quarter twenty-four (24) months following NERC Board of Trustees' adoption of PRC-005-3 or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

For Sudden Pressure Relaying Components, entities shall be 100% compliant on the first day of the first calendar quarter twelve (12) months following applicable regulatory approvals of PRC-005-X or, in those jurisdictions where no regulatory approval is required, on the first day of the first calendar quarter twenty-four (24) months following NERC Board of Trustees' adoption of PRC-005-X or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

Implementation Plan for Requirements R3 and R4:

1. For Protection System Component maintenance activities with maximum allowable intervals of less than one (1) calendar year, as established in Tables 1-1 through 1-5:

    - The entity shall be 100% compliant on the first day of the first calendar quarter eighteen (18) months following applicable regulatory approval of PRC-005-2, or in those jurisdictions where no regulatory approval is required, on the first day of the first calendar quarter thirty (30) months following the November 2012 NERC Board of Trustees' adoption of PRC-005-2 or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

2. For Protection System Component maintenance activities with maximum allowable intervals one (1) calendar year or more, but two (2) calendar years or less, as established in Tables 1-1 through 1-5:

    - The entity shall be 100% compliant on the first day of the first calendar quarter thirty-six (36) months following applicable regulatory approval of PRC-005-2 or, in those jurisdictions where no regulatory approval is required, on the first day of the first calendar quarter forty-eight (48) months following the November 2012 NERC Board of Trustees' adoption of PRC-005-2 or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

3. For Protection System Component maintenance activities with maximum allowable intervals of three (3) calendar years, as established in Tables 1-1 through 1-5:

    - The entity shall be at least 30% compliant on the first day of the first calendar quarter twenty-four (24) months following applicable regulatory approval of PRC-005-2 (or, for generating plants with scheduled outage intervals exceeding two years, at the conclusion of the first succeeding maintenance outage) or, in those jurisdictions where no regulatory approval is required, on the first day of the first calendar quarter thirty-six (36) months following the November 2012 NERC Board of Trustees' adoption of PRC-005-2 or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

- The entity shall be at least 60% compliant on the first day of the first calendar quarter thirty-six (36) months following applicable regulatory approval of PRC-005-2 or, in those jurisdictions where no regulatory approval is required, on the first day of the first calendar quarter forty-eight (48) months following NERC Board of Trustees' adoption of PRC-005-2 or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.
- The entity shall be 100% compliant on the first day of the first calendar quarter forty-eight (48) months following applicable regulatory approval of PRC-005-2 or, in those jurisdictions where no regulatory approval is required, on the first day of the first calendar quarter sixty (60) months following the November 2012 NERC Board of Trustees' adoption of PRC-005-2 or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

4. For Protection System Component maintenance activities with maximum allowable intervals of six (6) calendar years, as established in Tables 1-1 through 1-5 and Table 3:

- The entity shall be at least 30% compliant on the first day of the first calendar quarter thirty-six (36) months following applicable regulatory approval of PRC-005-2 (or, for generating plants with scheduled outage intervals exceeding three years, at the conclusion of the first succeeding maintenance outage) or, in those jurisdictions where no regulatory approval is required, on the first day of the first calendar quarter forty-eight (48) months following the November 2012 NERC Board of Trustees' adoption of PRC-005-2 or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.
- The entity shall be at least 60% compliant on the first day of the first calendar quarter sixty (60) months following applicable regulatory approval of PRC-005-2 or, in those jurisdictions where no regulatory approval is required, on the first day of the first calendar quarter seventy-two (72) months following the November 2012 NERC Board of Trustees' adoption of PRC-005-2 or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.
- The entity shall be 100% compliant on the first day of the first calendar quarter eighty-four (84) months following applicable regulatory approval of PRC-005-2 or, in those jurisdictions where no regulatory approval is required, on the first day of the first calendar quarter ninety-six (96) months following the November 2012 NERC Board of Trustees' adoption of PRC-005-2 or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

5. For Automatic Reclosing Component maintenance activities with maximum allowable intervals of six (6) calendar years, as established in Table 4-1, 4-2(a) and 4-2(b):

- The entity shall be at least 30% compliant on the first day of the first calendar quarter thirty-six (36) months following applicable regulatory approval of PRC-005-3 (or, for generating plants with scheduled outage intervals exceeding three years, at the conclusion of the first succeeding maintenance outage) or, in those jurisdictions where no regulatory approval is required, on the

first day of the first calendar quarter forty-eight (48) months following NERC Board of Trustees' adoption of PRC-005-3 or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

- The entity shall be at least 60% compliant on the first day of the first calendar quarter sixty (60) months following applicable regulatory approval of PRC-005-3 or, in those jurisdictions where no regulatory approval is required, on the first day of the first calendar quarter seventy-two (72) months following NERC Board of Trustees' adoption of PRC-005-3, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.
- The entity shall be 100% compliant on the first day of the first calendar quarter eighty-four (84) months following applicable regulatory approval of PRC-005-3 or, in those jurisdictions where no regulatory approval is required, on the first day of the first calendar quarter ninety-six (96) months following NERC Board of Trustees' adoption of PRC-005-3 or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

6. For Sudden Pressure Relaying Component maintenance activities with maximum allowable intervals of six (6) calendar years, as established in Table 5:

- The entity shall be at least 30% compliant on the first day of the first calendar quarter thirty-six (36) months following applicable regulatory approval of PRC-005-X (or, for generating plants with scheduled outage intervals exceeding three years, at the conclusion of the first succeeding maintenance outage) or, in those jurisdictions where no regulatory approval is required, on the first day of the first calendar quarter forty-eight (48) months following NERC Board of Trustees' adoption of PRC-005-X or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.
- The entity shall be at least 60% compliant on the first day of the first calendar quarter sixty (60) months following applicable regulatory approval of PRC-005-X or, in those jurisdictions where no regulatory approval is required, on the first day of the first calendar quarter seventy-two (72) months following NERC Board of Trustees' adoption of PRC-005-X, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.
- The entity shall be 100% compliant on the first day of the first calendar quarter eighty-four (84) months following applicable regulatory approval of PRC-005-X or, in those jurisdictions where no regulatory approval is required, on the first day of the first calendar quarter ninety-six (96) months following NERC Board of Trustees' adoption of PRC-005-X or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

7. For Protection System Component maintenance activities with maximum allowable intervals of twelve (12) calendar years, as established in Tables 1-1 through 1-5, Table 2, and Table 3:

- The entity shall be at least 30% compliant on the first day of the first calendar quarter sixty (60) months following applicable regulatory approval of PRC-005-2 or, in those jurisdictions where no regulatory approval is required, on the first day of the first calendar quarter seventy-two

(72) months following the November 2012 NERC Board of Trustees' adoption of PRC-005-2 or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

- The entity shall be at least 60% compliant on the first day of the first calendar quarter following one hundred eight (108) months following applicable regulatory approval of PRC-005-2 or, in those jurisdictions where no regulatory approval is required, on the first day of the first calendar quarter one hundred twenty (120) months following the November 2012 NERC Board of Trustees' adoption of PRC-005-2 or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.
- The entity shall be 100% compliant on the first day of the first calendar quarter one hundred fifty-six (156) months following applicable regulatory approval of PRC-005-2 or, in those jurisdictions where no regulatory approval is required, on the first day of the first calendar quarter one hundred sixty-eight (168) months following the November 2012 NERC Board of Trustees' adoption of PRC-005-2 or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

8. For Automatic Reclosing Component maintenance activities with maximum allowable intervals of twelve (12) calendar years, as established in Table 4-1, 4-2(a) and 4-2(b):
    - The entity shall be at least 30% compliant on the first day of the first calendar quarter sixty (60) months following applicable regulatory approval of PRC-005-3 or, in those jurisdictions where no regulatory approval is required, on the first day of the first calendar quarter seventy-two (72) months following NERC Board of Trustees' adoption of PRC-005-3 or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.
    - The entity shall be at least 60% compliant on the first day of the first calendar quarter following one hundred eight (108) months following applicable regulatory approval of PRC-005-3 or, in those jurisdictions where no regulatory approval is required, on the first day of the first calendar quarter one hundred twenty (120) months following NERC Board of Trustees' adoption of PRC-005-3 or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.
    - The entity shall be 100% compliant on the first day of the first calendar quarter one hundred fifty-six (156) months following applicable regulatory approval of PRC-005-3 or, in those jurisdictions where no regulatory approval is required, on the first day of the first calendar quarter one hundred sixty-eight (168) months following NERC Board of Trustees' adoption of PRC-005-3 or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.
9. For Sudden Pressure Relaying Component maintenance activities with maximum allowable intervals of twelve (12) calendar years, as established in Table 5:

- The entity shall be at least 30% compliant on the first day of the first calendar quarter sixty (60) months following applicable regulatory approval of PRC-005-X or, in those jurisdictions where no regulatory approval is required, on the first day of the first calendar quarter seventy-two (72) months following NERC Board of Trustees' adoption of PRC-005-X or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.
- The entity shall be at least 60% compliant on the first day of the first calendar quarter following one hundred eight (108) months following applicable regulatory approval of PRC-005-X or, in those jurisdictions where no regulatory approval is required, on the first day of the first calendar quarter one hundred twenty (120) months following NERC Board of Trustees' adoption of PRC-005-X or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.
- The entity shall be 100% compliant on the first day of the first calendar quarter one hundred fifty-six (156) months following applicable regulatory approval of PRC-005-X or, in those jurisdictions where no regulatory approval is required, on the first day of the first calendar quarter one hundred sixty-eight (168) months following NERC Board of Trustees' adoption of PRC-005-X or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

Applicability:

This standard applies to the following functional entities:

- Transmission Owner
- Generator Owner
- Distribution Provider

Implementation Plan

Protection System, Automatic Reclosing, and Sudden Pressure Relaying Maintenance
PRC-005-X

Standards Involved

Approval:

- PRC-005-X – Protection System, Automatic Reclosing, and Sudden Pressure Relaying Maintenance

Retirement:

- PRC-005-3 – Protection System and Automatic Reclosing Maintenance

Prerequisite Approvals:

N/A

Background:

~~Reliability Standard PRC-005-2 with its associated Implementation Plan was approved by FERC, effective on April 1, 2015. PRC-005-3 was approved by the NERC Board of Trustees in November 7, 2013 and has been filed with the applicable regulatory authorities for approval.~~ The Implementation Plan for PRC-005-X addresses Sudden Pressure Relaying, Protection Systems ~~-~~as outlined in PRC-005-2, and Automatic Reclosing Components as outlined in PRC-005-3~~, and Sudden Pressure Relaying~~. PRC-005-X establishes minimum maintenance activities for Sudden Pressure Relaying Component Types and the maximum allowable maintenance intervals for these maintenance activities. PRC-005-X requires entities to revise the Protection System Maintenance Program by now including Sudden Pressure Relaying Components.

~~This Implementation Plan adds:~~

- ~~The implementation of changes relating to Sudden Pressure Relaying maintenance and testing,~~
- ~~The implementation of new Requirement R6 for Balancing Authorities, and~~
- ~~The removal of the "Implementation Plan for Newly identified Automatic Reclosing Components Due to Generation Changes in the Balancing Authority Area" section, as the elements are now incorporated within the requirements of the standard itself.~~

~~Otherwise, the Implementation Plan has not been changed.~~

The Implementation Plan reflects consideration of the following:

1. The requirements set forth in the proposed standard, which carry forward requirements from PRC-005-2 and PRC-005-3, establish minimum maintenance activities for Protection System, Automatic Reclosing, and Sudden Pressure Relaying Component Types as well as the maximum allowable maintenance intervals for these maintenance activities. The maintenance activities established may not be presently performed by some entities and the established maximum allowable intervals may be shorter than those currently in use by some entities.
2. For entities not presently performing a maintenance activity or using longer intervals than the maximum allowable intervals established in the proposed standard, it is unrealistic for those entities to be immediately compliant with the new activities or intervals. Further, entities should be allowed to become compliant in such a way as to facilitate a continuing maintenance program.
3. Entities that have previously been performing maintenance within the newly specified intervals may not have all the documentation needed to demonstrate compliance with all of the maintenance activities specified.
4. The Implementation Schedule set forth below in this document carries forward the implementation schedules contained in PRC-005-2 and PRC-005-3 and includes changes needed to address the addition of Sudden Pressure Relaying Components in PRC-005-X.
5. The Implementation Schedule set forth in this document facilitates implementation of the more lengthy maintenance intervals within the revised Protection System Maintenance Program in approximately equally-distributed steps over those intervals prescribed for each respective maintenance activity in order that entities may implement this standard in a systematic method that facilitates an effective ongoing Protection System Maintenance Program.

General Considerations:

Each Transmission Owner, Generator Owner, and Distribution Provider shall maintain documentation to demonstrate compliance with PRC-005-1b, PRC-008-0, PRC-011-0, and PRC-017-0 until that entity meets the requirements of PRC-005-2, or the combined successor standards PRC-005-3 and PRC-005-X, in accordance with this implementation plan.

While entities are transitioning from PRC-005-1b, PRC-008-0, PRC-011-0, PRC-017-0~~to the requirements of PRC-005-2, or the combined successor standards PRC-005-3 and PRC-005-X~~, each entity must be prepared to identify:

- All of its applicable Protection System, Automatic Reclosing, and Sudden Pressure Relaying Components, and
- ~~Whether each~~Whether a C~~c~~omponent ~~has~~ was last ~~been~~ maintained according to PRC-005-1b, PRC-008-0, PRC-011-0, PRC-017-0, ~~PRC-005-2 (or the combined successor standards PRC-005-3~~or a successor PRC-005 standard~~ and PRC-005-X)~~. ~~, PRC-005-1b, PRC-008-0, PRC-011-0, PRC-017-0, or a combination thereof.~~

Effective Date

PRC-005-X shall become effective on the first day of the first calendar quarter after the date that the standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first calendar quarter after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

Retirement of Existing Standards:

Standards PRC-005-1b, PRC-008-0, PRC-011-0, and PRC-017-0 shall remain active and applicable to an entity's Protection System maintenance activities not yet transitioned to ~~throughout the phased implementation period of~~ PRC-005-2 or a successor standard during transition. ~~and shall be applicable to an entity's Protection System Component maintenance activities not yet transitioned to PRC-005-2.~~ Standards PRC-005-1b, PRC-008-0, PRC-011-0, and PRC-017-0 shall be retired at midnight of the day immediately prior to the first day of the first calendar quarter one hundred fifty-six (156) months following applicable regulatory approval of PRC-005-2 or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities; or, in those jurisdictions where no regulatory approval is required, at midnight of the day immediately prior to the first day of the first calendar quarter one hundred sixty-eight (168) months following the November 2012 NERC Board of Trustees' adoption of PRC-005-2.

PRC-005-2 shall be retired at midnight of the day immediately prior to the first day of the first calendar quarter, twelve (12) calendar months following applicable regulatory approval of PRC-005-3, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities; or, in those jurisdictions where no regulatory approval is required, the first day of the first calendar quarter twelve (12) calendar months from the date of Board of Trustees' adoption.

PRC-005-3 shall be retired at midnight of the day immediately prior to the first day of the first calendar quarter following applicable regulatory approval of PRC-005-X, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities; or, in those jurisdictions where no regulatory approval is required, the first day of the first calendar quarter from the date of Board of Trustees' adoption.

Implementation Plan for Definitions:

This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the Reliability Standards Glossary of Terms (Glossary) are not repeated here. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, the Glossary definition will be removed from the individual standard and added to the Glossary. The definitions of terms used only in the standard will remain in the standard.

Glossary Definition:

Protection System Maintenance Program (PSMP) — An ongoing program by which Protection System, Automatic Reclosing, and Sudden Pressure Relaying Components are kept in working order and proper operation of malfunctioning Components is restored. A maintenance program for a specific Component includes one or more of the following activities:

- Verify — Determine that the Component is functioning correctly.
- Monitor — Observe the routine in-service operation of the Component.
- Test — Apply signals to a Component to observe functional performance or output behavior, or to diagnose problems.
- Inspect — Examine for signs of Component failure, reduced performance or degradation.
- Calibrate — Adjust the operating threshold or measurement accuracy of a measuring element to meet the intended performance requirement.

Definitions of Terms Used in the Standard:

Sudden Pressure Relaying – A system that trips an interrupting device(s) to isolate the equipment it is monitoring and includes the following Components:

- Fault pressure relay – a mechanical relay or device that detects rapid changes in gas pressure, oil pressure, or oil flow that are indicative of Faults within liquid-filled, wire-wound equipment
- Control circuitry associated with a fault pressure relay

Component Type –

- Any one of the five specific elements of a Protection System.
- Any one of the two specific elements of Automatic Reclosing.
- Any one of the two specific elements of Sudden Pressure Relaying.

Component – Any individual discrete piece of equipment included in a Protection System, Automatic Reclosing, or Sudden Pressure Relaying.

Countable Event – A failure of a Component requiring repair or replacement, any condition discovered during the maintenance activities in Tables 1-1 through 1-5, Table 3, Tables 4-1 through 4-2, and Table 5, which requires corrective action or a Protection System Misoperation attributed to hardware failure or calibration failure. Misoperations due to product design errors, software errors, relay settings different from specified settings, Protection System Component, Automatic Reclosing, or Sudden Pressure Relaying configuration or application errors are not included in Countable Events.

Implementation Plan for New or Revised Definitions:

New and revised definitions (Sudden Pressure Relaying, Protection System Maintenance Program, Component Type, Component, and Countable Event) shall become effective after the date that the definitions are approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a definition to go into effect. Where approval by an applicable governmental authority is not required, the definitions shall become effective on the first day of the first calendar quarter after the date the definitions are adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

Implementation Plan for Requirements R1, R2, and R5:

For Protection System Components, entities shall be 100% compliant on the first day of the first calendar quarter twelve (12) months following applicable regulatory approvals of PRC-005-2 or, in those jurisdictions where no regulatory approval is required, on the first day of the first calendar quarter twenty-four (24) months following the November 2012 NERC Board of Trustees' adoption of PRC-005-2 or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

For Automatic Reclosing Components, entities shall be 100% compliant on the first day of the first calendar quarter twelve (12) months following applicable regulatory approvals of PRC-005-3 or, in those jurisdictions where no regulatory approval is required, on the first day of the first calendar quarter twenty-four (24) months following NERC Board of Trustees' adoption of PRC-005-3 or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.
For Sudden Pressure Relaying Components, entities shall be 100% compliant on the first day of the first calendar quarter twelve (12) months following applicable regulatory approvals of PRC-005-X or, in those jurisdictions where no regulatory approval is required, on the first day of the first calendar quarter twenty-four (24) months following NERC Board of Trustees' adoption of PRC-005-X or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

Implementation Plan for Requirements R3 and R4:

1. For Protection System Component maintenance activities with maximum allowable intervals of less than one (1) calendar year, as established in Tables 1-1 through 1-5:
   - The entity shall be 100% compliant on the first day of the first calendar quarter eighteen (18) months following applicable regulatory approval of PRC-005-2, or in those jurisdictions where no regulatory approval is required, on the first day of the first calendar quarter thirty (30) months following the November 2012 NERC Board of Trustees' adoption of PRC-005-2 or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.
2. For Protection System Component maintenance activities with maximum allowable intervals one (1) calendar year or more, but two (2) calendar years or less, as established in Tables 1-1 through 1-5:

- The entity shall be 100% compliant on the first day of the first calendar quarter thirty-six (36) months following applicable regulatory approval of PRC-005-2 or, in those jurisdictions where no regulatory approval is required, on the first day of the first calendar quarter forty-eight (48) months following the November 2012 NERC Board of Trustees' adoption of PRC-005-2 or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

3. For Protection System Component maintenance activities with maximum allowable intervals of three (3) calendar years, as established in Tables 1-1 through 1-5:

- The entity shall be at least 30% compliant on the first day of the first calendar quarter twenty-four (24) months following applicable regulatory approval of PRC-005-2 (or, for generating plants with scheduled outage intervals exceeding two years, at the conclusion of the first succeeding maintenance outage) or, in those jurisdictions where no regulatory approval is required, on the first day of the first calendar quarter thirty-six (36) months following the November 2012 NERC Board of Trustees' adoption of PRC-005-2 or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.
- The entity shall be at least 60% compliant on the first day of the first calendar quarter thirty-six (36) months following applicable regulatory approval of PRC-005-2 or, in those jurisdictions where no regulatory approval is required, on the first day of the first calendar quarter forty-eight (48) months following NERC Board of Trustees' adoption of PRC-005-2 or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.
- The entity shall be 100% compliant on the first day of the first calendar quarter forty-eight (48) months following applicable regulatory approval of PRC-005-2 or, in those jurisdictions where no regulatory approval is required, on the first day of the first calendar quarter sixty (60) months following the November 2012 NERC Board of Trustees' adoption of PRC-005-2 or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

4. For Protection System Component maintenance activities with maximum allowable intervals of six (6) calendar years, as established in Tables 1-1 through 1-5 and Table 3:

- The entity shall be at least 30% compliant on the first day of the first calendar quarter thirty-six (36) months following applicable regulatory approval of PRC-005-2 (or, for generating plants with scheduled outage intervals exceeding three years, at the conclusion of the first succeeding maintenance outage) or, in those jurisdictions where no regulatory approval is required, on the first day of the first calendar quarter forty-eight (48) months following the November 2012 NERC Board of Trustees' adoption of PRC-005-2 or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.
- The entity shall be at least 60% compliant on the first day of the first calendar quarter sixty (60) months following applicable regulatory approval of PRC-005-2 or, in those jurisdictions where no regulatory approval is required, on the first day of the first calendar quarter seventy-two

(72) months following the November 2012 NERC Board of Trustees' adoption of PRC-005-2 or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

- The entity shall be 100% compliant on the first day of the first calendar quarter eighty-four (84) months following applicable regulatory approval of PRC-005-2 or, in those jurisdictions where no regulatory approval is required, on the first day of the first calendar quarter ninety-six (96) months following the November 2012 NERC Board of Trustees' adoption of PRC-005-2 or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

5. For Automatic Reclosing Component maintenance activities with maximum allowable intervals of six (6) calendar years, as established in Table 4-1, 4-2(a) and 4-2(b):

   - The entity shall be at least 30% compliant on the first day of the first calendar quarter thirty-six (36) months following applicable regulatory approval of PRC-005-3 (or, for generating plants with scheduled outage intervals exceeding three years, at the conclusion of the first succeeding maintenance outage) or, in those jurisdictions where no regulatory approval is required, on the first day of the first calendar quarter forty-eight (48) months following NERC Board of Trustees' adoption of PRC-005-3 or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.
   - The entity shall be at least 60% compliant on the first day of the first calendar quarter sixty (60) months following applicable regulatory approval of PRC-005-3 or, in those jurisdictions where no regulatory approval is required, on the first day of the first calendar quarter seventy-two (72) months following NERC Board of Trustees' adoption of PRC-005-3, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.
   - The entity shall be 100% compliant on the first day of the first calendar quarter eighty-four (84) months following applicable regulatory approval of PRC-005-3 or, in those jurisdictions where no regulatory approval is required, on the first day of the first calendar quarter ninety-six (96) months following NERC Board of Trustees' adoption of PRC-005-3 or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

6. For Sudden Pressure Relaying Component maintenance activities with maximum allowable intervals of six (6) calendar years, as established in Table 5:

   - The entity shall be at least 30% compliant on the first day of the first calendar quarter thirty-six (36) months following applicable regulatory approval of PRC-005-X (or, for generating plants with scheduled outage intervals exceeding three years, at the conclusion of the first succeeding maintenance outage) or, in those jurisdictions where no regulatory approval is required, on the first day of the first calendar quarter forty-eight (48) months following NERC Board of Trustees' adoption of PRC-005-X or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

- The entity shall be at least 60% compliant on the first day of the first calendar quarter sixty (60) months following applicable regulatory approval of PRC-005-X or, in those jurisdictions where no regulatory approval is required, on the first day of the first calendar quarter seventy-two (72) months following NERC Board of Trustees' adoption of PRC-005-X, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.
- The entity shall be 100% compliant on the first day of the first calendar quarter eighty-four (84) months following applicable regulatory approval of PRC-005-X or, in those jurisdictions where no regulatory approval is required, on the first day of the first calendar quarter ninety-six (96) months following NERC Board of Trustees' adoption of PRC-005-X or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

7. For Protection System Component maintenance activities with maximum allowable intervals of twelve (12) calendar years, as established in Tables 1-1 through 1-5, Table 2, and Table 3:

- The entity shall be at least 30% compliant on the first day of the first calendar quarter sixty (60) months following applicable regulatory approval of PRC-005-2 or, in those jurisdictions where no regulatory approval is required, on the first day of the first calendar quarter seventy-two (72) months following the November 2012 NERC Board of Trustees' adoption of PRC-005-2 or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.
- The entity shall be at least 60% compliant on the first day of the first calendar quarter following one hundred eight (108) months following applicable regulatory approval of PRC-005-2 or, in those jurisdictions where no regulatory approval is required, on the first day of the first calendar quarter one hundred twenty (120) months following the November 2012 NERC Board of Trustees' adoption of PRC-005-2 or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.
- The entity shall be 100% compliant on the first day of the first calendar quarter one hundred fifty-six (156) months following applicable regulatory approval of PRC-005-2 or, in those jurisdictions where no regulatory approval is required, on the first day of the first calendar quarter one hundred sixty-eight (168) months following the November 2012 NERC Board of Trustees' adoption of PRC-005-2 or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

8. For Automatic Reclosing Component maintenance activities with maximum allowable intervals of twelve (12) calendar years, as established in Table 4-1, 4-2(a) and 4-2(b)~~Table 4~~:

- The entity shall be at least 30% compliant on the first day of the first calendar quarter sixty (60) months following applicable regulatory approval of PRC-005-3 or, in those jurisdictions where no regulatory approval is required, on the first day of the first calendar quarter seventy-two (72) months following NERC Board of Trustees' adoption of PRC-005-3 or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

- The entity shall be at least 60% compliant on the first day of the first calendar quarter following one hundred eight (108) months following applicable regulatory approval of PRC-005-3 or, in those jurisdictions where no regulatory approval is required, on the first day of the first calendar quarter one hundred twenty (120) months following NERC Board of Trustees' adoption of PRC-005-3 or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.
- The entity shall be 100% compliant on the first day of the first calendar quarter one hundred fifty-six (156) months following applicable regulatory approval of PRC-005-3 or, in those jurisdictions where no regulatory approval is required, on the first day of the first calendar quarter one hundred sixty-eight (168) months following NERC Board of Trustees' adoption of PRC-005-3 or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

9. For Sudden Pressure Relaying Component maintenance activities with maximum allowable intervals of twelve (12) calendar years, as established in Table 5:
   - The entity shall be at least 30% compliant on the first day of the first calendar quarter sixty (60) months following applicable regulatory approval of PRC-005-X or, in those jurisdictions where no regulatory approval is required, on the first day of the first calendar quarter seventy-two (72) months following NERC Board of Trustees' adoption of PRC-005-X or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.
   - The entity shall be at least 60% compliant on the first day of the first calendar quarter following one hundred eight (108) months following applicable regulatory approval of PRC-005-X or, in those jurisdictions where no regulatory approval is required, on the first day of the first calendar quarter one hundred twenty (120) months following NERC Board of Trustees' adoption of PRC-005-X or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.
   - The entity shall be 100% compliant on the first day of the first calendar quarter one hundred fifty-six (156) months following applicable regulatory approval of PRC-005-X or, in those jurisdictions where no regulatory approval is required, on the first day of the first calendar quarter one hundred sixty-eight (168) months following NERC Board of Trustees' adoption of PRC-005-X or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

Applicability:

This standard applies to the following functional entities:

- Transmission Owner
- Generator Owner
- Distribution Provider

- ~~Balancing Authority~~

NERC

NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

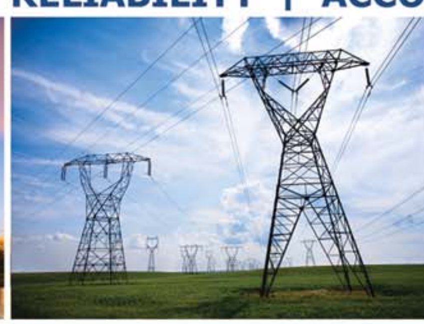
Supplementary Reference and FAQ

PRC-005-X Protection System Maintenance

April 2014

RELIABILITY | ACCOUNTABILITY



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1. Introduction and Summary

Note: This supplementary reference for PRC-005-X is neither mandatory nor enforceable.

NERC currently has four Reliability Standards that are mandatory and enforceable in the United States and Canada and address various aspects of maintenance and testing of Protection and Control Systems.

These standards are:

PRC-005-1b — Transmission and Generation Protection System Maintenance and Testing

PRC-008-0 — Underfrequency Load Shedding Equipment Maintenance Programs

PRC-011-0 — UVLS System Maintenance and Testing

PRC-017-0 — Special Protection System Maintenance and Testing

While these standards require that applicable entities have a maintenance program for Protection Systems, and that these entities must be able to demonstrate they are carrying out such a program, there are no specifics regarding the technical requirements for Protection System maintenance programs. Furthermore, FERC Order 693 directed additional modifications respective to Protection System maintenance programs. PRC-005-3 will replace PRC-005-2 which combined and replaced PRC-005, PRC-008, PRC-011 and PRC-017. PRC-005-3 adds Automatic Reclosing to PRC-005-2. PRC-005-2 addressed these directed modifications and replaces PRC-005, PRC-008, PRC-011 and PRC-017.

FERC Order 758 further directed that maintenance of reclosing relays and sudden pressure relays that affect the reliable operation of the Bulk Power System be addressed. PRC-005-3 addresses this directive regarding reclosing relays, and, when approved, will supersede PRC-005-2. PRC-005-X addresses this directive regarding sudden pressure relays and, when approved, will supersede PRC-005-3.

This document augments the Supplementary Reference and FAQ previously developed for PRC-005-2 by including discussion relevant to Automatic Reclosing added in PRC-005-3 and Sudden Pressure Relaying in PRC-005-X.

2. Need for Verifying Protection System Performance

Protective relays have been described as silent sentinels, and do not generally demonstrate their performance until a Fault or other power system problem requires that they operate to protect power system Elements, or even the entire Bulk Electric System (BES). Lacking Faults, switching operations or system problems, the Protection Systems may not operate, beyond static operation, for extended periods. A Misoperation - a false operation of a Protection System or a failure of the Protection System to operate, as designed, when needed - can result in equipment damage, personnel hazards, and wide-area Disturbances or unnecessary customer outages. Maintenance or testing programs are used to determine the performance and availability of Protection Systems.

Typically, utilities have tested Protection Systems at fixed time intervals, unless they had some incidental evidence that a particular Protection System was not behaving as expected. Testing practices vary widely across the industry. Testing has included system functionality, calibration of measuring devices, and correctness of settings. Typically, a Protection System must be visited at its installation site and, in many cases, removed from service for this testing.

Fundamentally, a Reliability Standard for Protection System Maintenance and Testing requires the performance of the maintenance activities that are necessary to detect and correct plausible age and service related degradation of the Protection System components, such that a properly built and commissioned Protection System will continue to function as designed over its service life.

Similarly station batteries, which are an important part of the station dc supply, are not called upon to provide instantaneous dc power to the Protection System until power is required by the Protection System to operate circuit breakers or interrupting devices to clear Faults or to isolate equipment.

2.1 Existing NERC Standards for Protection System Maintenance and Testing

For critical BES protection functions, NERC standards have required that each utility or asset owner define a testing program. The starting point is the existing Standard PRC-005, briefly restated as follows:

Purpose: To document and implement programs for the maintenance of all Protection Systems affecting the reliability of the Bulk Electric System (BES) so that these Protection Systems are kept in working order.

PRC-005-X is not specific on where the boundaries of the Protection Systems lie. However, the definition of Protection System in the NERC Glossary of Terms used in Reliability Standards indicates what must be included as a minimum.

At the beginning of the project to develop PRC-005-2, the definition of Protection System was:

Protective relays, associated communications Systems, voltage and current sensing devices, station batteries and dc control circuitry.

Applicability: Owners of generation and transmission Protection Systems.

Requirements: The owner shall have a documented maintenance program with test intervals. The owner must keep records showing that the maintenance was performed at the specified intervals.

2.2 Protection System Definition

The most recently approved definition of Protection Systems is:

- Protective relays which respond to electrical quantities,
- Communications systems necessary for correct operation of protective functions,
- Voltage and current sensing devices providing inputs to protective relays,
- Station dc supply associated with protective functions (including station batteries, battery chargers, and non-battery-based dc supply), and
- Control circuitry associated with protective functions through the trip coil(s) of the circuit breakers or other interrupting devices.

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:

"*…that are installed for the purpose of detecting Faults on BES Elements (lines, buses, transformers, etc.).*"

The drafting team intends that this standard will follow with any definition of the Bulk Electric System. There should be no ambiguity; if the Element is a BES Element, then the Protection System protecting that Element should then be included within this standard. If there is regional variation to the definition, then there will be a corresponding regional variation to the Protection Systems that fall under this standard.

There is no way for the Standard Drafting Team to know whether a specific 230KV line, 115KV line (even 69KV line), for example, should be included or excluded. Therefore, the team set the clear intent that the standard language should simply be applicable to Protection Systems for BES Elements.

The BES is a NERC defined term that, from time to time, may undergo revisions. Additionally, there may even be regional variations that are allowed in the present and future definitions. See the NERC Glossary of Terms for the present, in-force definition. See the applicable Regional Reliability Organization for any applicable allowed variations.

While this standard will undergo revisions in the future, this standard will not attempt to keep up with revisions to the NERC definition of BES, but, rather, simply make BES Protection Systems applicable.

The Standard is applied to Generator Owners (GO) and Transmission Owners (TO) because GOs and TOs have equipment that is BES equipment. The standard brings in Distribution Providers (DP) because, depending on the station configuration of a particular substation, there may be

Protection System equipment installed at a non-transmission voltage level (Distribution Provider equipment) that is wholly or partially installed to protect the BES. PRC-005-X would apply to this equipment. An example is underfrequency load-shedding, which is frequently applied well down into the distribution system to meet PRC-007-0.

PRC-005-2 replaced the existing PRC-005, PRC-008, PRC-011 and PRC-017. Much of the original intent of those standards was carried forward whenever it was possible to continue the intent without a disagreement with FERC Order 693. For example, the original PRC-008 was constructed quite differently than the original PRC-005. The drafting team agrees with the intent of this and notes that distributed tripping schemes would have to exhibit multiple failures to trip before they would prove to be significant, as opposed to a single failure to trip of, for example, a transmission Protection System Bus Differential lock-out relay. While many failures of these distribution breakers could add up to be significant, it is also believed that distribution breakers are operated often on just Fault clearing duty; and, therefore, the distribution circuit breakers are operated at least as frequently as stipulated in any requirement in this standard.

Additionally, since PRC-005-2 replaced PRC-011, it will be important to make the distinction between under-voltage Protection Systems that protect individual Loads and Protection Systems that are UVLS schemes that protect the BES. Any UVLS scheme that had been applicable under PRC-011 is now applicable under PRC-005-2. An example of an under-voltage load-shedding scheme that is not applicable to this standard is one in which the tripping action was intended to prevent low distribution voltage to a specific Load from a Transmission system that was intact except for the line that was out of service, as opposed to preventing a Cascading outage or Transmission system collapse.

It had been correctly noted that the devices needed for PRC-011 are the very same types of devices needed in PRC-005.

Thus, a standard written for Protection Systems of the BES can easily make the needed requirements for Protection Systems, and replace some other standards at the same time.

2.3.1 Frequently Asked Questions:

What exactly is the BES, or Bulk Electric System?

BES is the abbreviation for Bulk Electric System. BES is a term in the Glossary of Terms used in Reliability Standards, and is not being modified within this draft standard.
NERC's approved definition of Bulk Electric System is:

As defined by the Regional Reliability Organization, the electrical generation resources, transmission lines, Interconnections with neighboring Systems, and associated equipment, generally operated at voltages of 100 kV or higher. Radial transmission Facilities serving only Load with one transmission source are generally not included in this definition.

The BES definition is presently undergoing the process of revision.

Each regional entity implements a definition of the Bulk Electric System that is based on this NERC definition; in some cases, supplemented by additional criteria. These regional definitions have been documented and provided to FERC as part of a *June 14, 2007 Informational Filing*.

Why is Distribution Provider included within the Applicable Entities and as a responsible entity within several of the requirements? Wouldn't anyone having relevant Facilities be a Transmission Owner?

Depending on the station configuration of a particular substation, there may be Protection System equipment installed at a non-transmission voltage level (Distribution Provider equipment) that is wholly or partially installed to protect the BES. PRC-005-X applies to this equipment. An example is underfrequency load-shedding, which is frequently applied well down into the distribution system to meet PRC-007-0.

We have an under voltage load-shedding (UVLS) system in place that prevents one of our distribution substations from supplying extremely low voltage in the case of a specific transmission line outage. The transmission line is part of the BES. Does this mean that our UVLS system falls within this standard?

The situation, as stated, indicates that the tripping action was intended to prevent low distribution voltage to a specific Load from a Transmission System that was intact, except for the line that was out of service, as opposed to preventing Cascading outage or Transmission System Collapse.

This standard is not applicable to this UVLS.

We have a UFLS or UVLS scheme that sheds the necessary Load through distribution-side circuit breakers and circuit reclosers. Do the trip-test requirements for circuit breakers apply to our situation?

No. Distributed tripping schemes would have to exhibit multiple failures to trip before they would prove to be significant, as opposed to a single failure to trip of, for example, a transmission Protection System bus differential lock-out relay. While many failures of these distribution breakers could add up to be significant, it is also believed that distribution breakers are operated often on just Fault clearing duty; and, therefore, the distribution circuit breakers are operated at least as frequently as any requirements that might have appeared in this standard.

We have a UFLS scheme that, in some locales, sheds the necessary Load through non-BES circuit breakers and, occasionally, even circuit switchers. Do the trip-test requirements for circuit breakers apply to our situation?

If your "non-BES circuit breaker" has been brought into this standard by the inclusion of UFLS requirements, and otherwise would not have been brought into this standard, then the answer is that there are no trip-test requirements. For these devices that are otherwise non-BES assets, these tripping schemes would have to exhibit multiple failures to trip before they would prove to be as significant as, for example, a single failure to trip of a transmission Protection System bus differential lock-out relay.

How does the "Facilities" section of "Applicability" track with the standards that will be retired once PRC-005-2 becomes effective?

In establishing PRC-005-2, the drafting team combined legacy standards PRC-005-1b, PRC-008-0, PRC-011-0, and PRC-017-0. The merger of the subject matter of these standards is reflected in Applicability 4.2.

The intent of the drafting team is that the legacy standards be reflected in PRC-005-2 as follows:

- Applicability of PRC-005-1b for Protection Systems relating to non-generator elements of the BES is addressed in 4.2.1;
- Applicability of PRC-008-0 for underfrequency load shedding systems is addressed in 4.2.2;
- Applicability of PRC-011-0 for undervoltage load shedding relays is addressed in 4.2.3;
- Applicability of PRC-017-0 for Special Protection Systems is addressed in 4.2.4;
- Applicability of PRC-005-1b for Protection Systems for BES generators is addressed in 4.2.5.

2.4 Applicable Relays

The NERC Glossary definition has a Protection System including relays, dc supply, current and voltage sensing devices, dc control circuitry and associated communications circuits. The relays to which this standard applies are those protective relays that respond to electrical quantities and provide a trip output to trip coils, dc control circuitry or associated communications equipment. This definition extends to IEEE Device No. 86 (lockout relay) and IEEE Device No. 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.

Relays that respond to non-electrical inputs or impulses (such as, but not limited to, vibration, seismic, thermal or gas accumulation) are not included.

Automatic Reclosing is addressed in PRC-005-3 by explicitly addressing them outside the definition of Protection System. The specific locations for applicable Automatic Reclosing are addressed in Applicability Section 4.2.7.

Sudden Pressure Relaying is addressed in PRC-005-X by explicitly addressing them outside the definition of Protection System. The specific locations for applicable Sudden Pressure Relaying are addressed in Applicability Section 4.2.1, 4.2.5 and 4.2.6.

2.4.1 Frequently Asked Questions:

Are power circuit reclosers, reclosing relays, closing circuits and auto-restoration schemes covered in this Standard?

Yes. Automatic Reclosing includes reclosing relays and the associated dc control circuitry. Section 4.2.6 of the Applicability specifically limits the applicable reclosing relays to:

4.2.6 Automatic Reclosing

4.2.6.1 Automatic Reclosing applied on the terminals of Elements connected to the BES bus located at generating plant substations where the total installed gross generating plant capacity is greater than the gross capacity of the largest BES generating unit within the Balancing Authority Area.

4.2.6.2 Automatic Reclosing applied on the terminals of all BES Elements at substations one bus away from generating plants specified in Section 4.2.6.1 when the substation is less than 10 circuit-miles from the generating plant substation.

4.2.6.3 Automatic Reclosing applied as an integral part of a SPS specified in Section 4.2.4.

Further, Footnote 1 to Applicability Section 4.2.6 establishes that Automatic Reclosing addressed in 4.2.6.1 and 4.2.6.2 may be excluded if the equipment owner can demonstrate that a close-in three-phase fault present for twice the normal clearing time (capturing a minimum trip-close-trip time delay) does not result in a total loss of gross generation in the Interconnection exceeding the gross capacity of the largest BES unit within the Balancing Authority Area where the Automatic Reclosing is applied.

The Applicability as detailed above was recommended by the NERC System Analysis and Modeling Subcommittee (SAMS) after a lengthy review of the use of reclosing within the BES. SAMS concluded that automatic reclosing is largely implemented throughout the BES as an operating convenience, and that automatic reclosing mal-performance affects BES reliability only when the reclosing is part of a Special Protection System, or when premature autoreclosing has the potential to cause generating unit or plant instability. A technical report, "Considerations for Maintenance and Testing of Autoreclosing Schemes — November 2012", is referenced in PRC-005-3 and provides a more detailed discussion of these concerns.

How do I interpret Applicability Section 4.2.6 to determine applicability in the following examples:

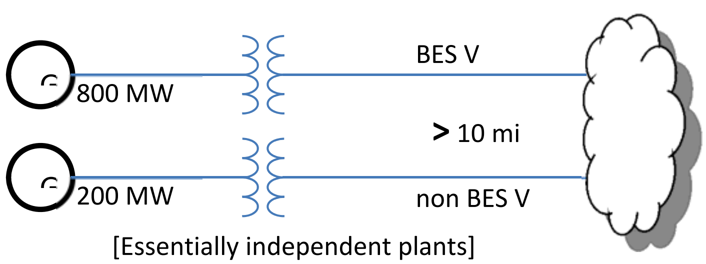
At my generating plant substation, I have a total of 800 MW connected to one voltage level and 200 MW connected to another voltage level. How do I determine my gross capacity? Where do I consider Automatic Reclosing to be applicable?

Scenario number 1:

The 800 MW of generation is connected to a BES voltage level bus, the 200 MW unit is connected to a non-BES voltage level bus, and there is no connection between the two buses locally or within 10 circuit miles from the generating plant substation. The largest single unit in the BA area is 750 MW.

In this case, the total installed gross generating capacity would be 800 MW. The two units are essentially independent plants.

The BES voltage level bus is considered to be the bus to which the 800 MW of generation is connected. Any BES Automatic Reclosing at this location, as well as other locations within 10 circuit miles, is considered to be applicable because 800 MW exceeds the largest single unit in the BA area.



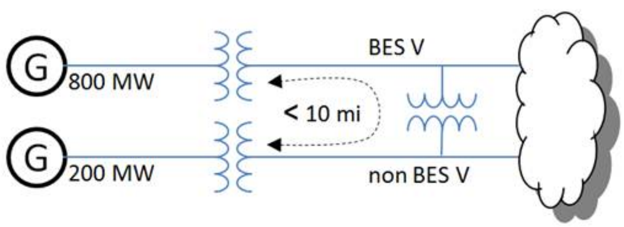
Gross Capacity	Automatic Reclosing in scope
800 MW	BES V

Scenario number 2:

The 800 MW of generation is connected to a BES voltage level bus, the 200 MW unit is connected to a non-BES voltage level bus, and there is a connection between the two buses locally or within 10 circuit miles from the generating plant substation. The largest single unit in the BA area is 750 MW.

In this case, reclosing into a fault on the BES system could impact the stability of the non-BES-connected generating units. Therefore, the total installed gross generating capacity would be 1000 MW.

The BES voltage level bus is considered to be the bus to which the 800 MW of generation is connected. Any BES Automatic Reclosing at this location, as well as other locations within 10 circuit miles, is considered to be applicable because total of 1000 MW exceeds the largest single unit in the BA area. However, the Automatic Reclosing on the non-BES voltage level bus is not applicable.



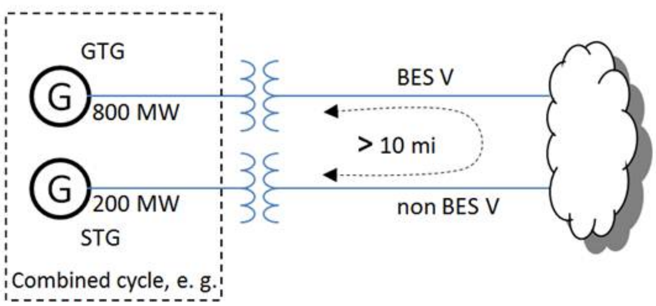
Gross Capacity	Automatic Reclosing in scope
1000 MW	BES V

Scenario number 3:

The 800 MW of generation is connected to a BES voltage level bus, the 200 MW unit is connected to a non-BES voltage level bus, and there is no connection between the two buses locally or within 10 circuit miles from the generating plant substation but the generating units connected at the BES voltage level do not operate independently of the units connected at the non BES voltage level (e.g., a combined cycle facility where 800 MW of combustion turbines are connected at a BES voltage level whose exhaust is used to power a 200 MW steam unit connected to a non BES voltage level. The largest single unit in the BA area is 750 MW.

In this case, the total installed gross generating capacity would be 1000 MW. Therefore, reclosing into a fault on the BES voltage level would result in a loss of the 800 MW combustion turbines and subsequently result in the loss of the 200 MW steam unit because of the loss of the heat source to its boiler.

The BES voltage level bus is considered to be the bus to which the 800 MW of generation is connected. Any BES Automatic Reclosing at this location, as well as other locations within 10 circuit miles, is considered to be applicable because total of 1000 MW exceeds the largest single unit in the BA area. However, the Automatic Reclosing on the non-BES voltage level bus is not applicable.



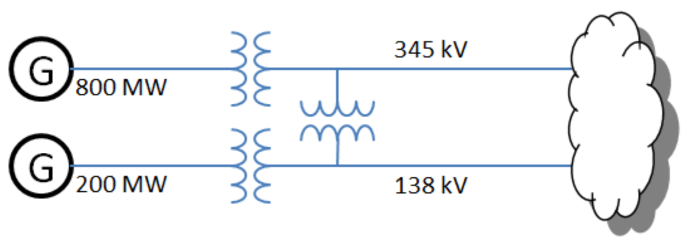
<u>Gross Capacity</u>	<u>Automatic Reclosing in scope</u>
1000 MW	BES V

Scenario 4

The 800 MW of generation is connected at 345 kV and the 200 MW is connected at 138 kV with an autotransformer at the generating plant substation connecting the two voltage levels. The largest single unit in the BA area is 900 MW.

In this case, the total installed gross generating capacity would be 1000 MW and section 4.2.6.1 would be applicable to both the 345 kV Automatic Reclosing Components and the 138 kV Automatic Reclosing Components, since the total capacity of 1000 MW is larger than the largest single unit in the BA area.

However, if the 345 kV and the 138 kV systems can be shown to be uncoupled such that the 138 kV reclosing relays will not affect the stability of the 345 kV generating units then the 138 kV Automatic Reclosing Components need not be included per section 4.2.6.1.



Gross Capacity	**Automatic Reclosing in scope**
1000 MW	BOTH*

* The study detailed in Footnote 1 of the draft standard may eliminate the 138 kV Automatic Reclosing Components and/or the 345 kV Automatic Reclosing Components

Why does 4.2.6.2 specify “10 circuit miles”?

As noted in “Considerations for Maintenance and Testing of Autoreclosing Schemes — November 2012”, transmission line impedance on the order of one mile away typically provides adequate impedance to prevent generating unit instability and a 10 mile threshold provides sufficient margin.

Should I use MVA or MW when determining the installed gross generating plant capacity?

Be consistent with the rating used by the Balancing Authority for the largest BES generating unit within their area.

What value should we use for generating plant capacity in 4.2.6.1?

Use the value reported to the Balance Authority for generating plant capacity for planning and modeling purposes. This can be nameplate or other values based on generating plant limitations such as boiler or turbine ratings.

What is considered to be “one bus away” from the generation?

The BES voltage level bus is considered to be the generating plant substation bus to which the generator step-up transformer is connected. “One bus away” is the next bus, connected by either a transmission line or transformer.

I use my protective relays only as sources of metered quantities and breaker status for SCADA and EMS through a substation distributed RTU or data concentrator to the control center. What are the maintenance requirements for the relays?

This standard addresses Protection Systems that are installed for the purpose of detecting Faults on BES Elements (lines, buses, transformers, etc.). Protective relays, providing only the functions mentioned in the question, are not included.

Are Reverse Power Relays installed on the low-voltage side of distribution banks considered to be components of “Protection Systems that are installed for the purpose of detecting Faults on BES Elements (lines, buses, transformers, etc.)”?

Reverse power relays are often installed to detect situations where the transmission source becomes de-energized and the distribution bank remains energized from a source on the low-voltage side of the transformer and the settings are calculated based on the charging current of the transformer from the low-voltage side. Although these relays may operate as a result of a fault on a BES element, they are not ‘installed for the purpose of detecting’ these faults.

Why is the maintenance of Sudden Pressure Relaying being addressed in PRC-005-X?

Proper performance of Sudden Pressure Relaying supports the reliability of the BES because fault pressure relays can detect rapid changes in gas pressure, oil pressure, or oil flow that are indicative of faults within liquid-filled, wire-wound equipment such as turn-to-turn faults which may be undetected by Protection Systems. Additionally, Sudden Pressure Relaying can quickly detect faults and operate to limit damage to liquid-filled, wire-wound equipment.

What type of devices are classified as fault pressure relay?

There are three main types of fault pressure relays; rapid gas pressure rise, rapid oil pressure rise, and rapid oil flow devices.

Rapid gas pressure devices monitor the pressure in the space above the oil (or other liquid), and initiate tripping action for a rapid rise in gas pressure resulting from the rapid expansion of the liquid caused by a fault. The sensor is located in the gas space.

Rapid oil pressure devices monitor the pressure in the oil (or other liquid), and initiate tripping action for a rapid pressure rise caused by a fault. The sensor is located in the liquid.

Rapid oil flow devices (“Buchholz”) monitor the liquid flow between a transformer/reactor and its conservator. Normal liquid flow occurs continuously with ambient temperature changes and with internal heating from loading and does not operate the rapid oil flow device. However, when an internal arc happens a sudden expansion of liquid can be monitored as rapid liquid flow from the transformer into the conservator resulting in actuation of the rapid oil flow device.

Are sudden pressure relays that only initiate an alarm included in the scope of PRC-005-X?

No, the definition of Sudden Pressure Relaying specifies only those that trip an interrupting device(s) to isolate the equipment it is monitoring.

Is Sudden Pressure Relaying installed on distribution transformers included in PRC-005-X?

No, Applicability 4.2.1, 4.2.5.2, 4.2.5.3, 4.2.6.1, explicitly describe what Sudden Pressure Relaying is included within the standard.

Are non-electrical sensing devices (other than fault pressure relays) such as as low oil level or high winding temperatures included in PRC-005-X?

No, based on the SPCS technical document, “Sudden Pressure Relays and Other Devices that Respond to Non-Electrical Quantities – December 2013” the only applicable non-electrical sensing devices are fault pressure relays.

The standard specifically mentions auxiliary and lock-out relays. What is an auxiliary tripping relay?

An auxiliary relay, IEEE Device No. 94, is described in IEEE Standard C37.2-2008 as: “A device that functions to trip a circuit breaker, contactor, or equipment; to permit immediate tripping by other devices; or to prevent immediate reclosing of a circuit interrupter if it should open automatically, even though its closing circuit is maintained closed.”

What is a lock-out relay?

A lock-out relay, IEEE Device No. 86, is described in IEEE Standard C37.2 as: “A device that trips and maintains the associated equipment or devices inoperative until it is reset by an operator, either locally or remotely.”

3. Protection System and Automatic Reclosing Product Generations

The likelihood of failure and the ability to observe the operational state of a critical Protection System and Automatic Reclosing both depend on the technological generation of the relays, as well as how long they have been in service. Unlike many other transmission asset groups, protection and control systems have seen dramatic technological changes spanning several generations. During the past 20 years, major functional advances are primarily due to the introduction of microprocessor technology for power system devices, such as primary measuring relays, monitoring devices, control Systems, and telecommunications equipment.

Modern microprocessor-based relays have six significant traits that impact a maintenance strategy:

- Self-monitoring capability - the processors can check themselves, peripheral circuits, and some connected substation inputs and outputs, such as trip coil continuity. Most relay users are aware that these relays have self-monitoring, but are not focusing on exactly what internal functions are actually being monitored. As explained further below, every element critical to the Protection System must be monitored, or else verified periodically.
- Ability to capture Fault records showing how the Protection System responded to a Fault in its zone of protection, or to a nearby Fault for which it is required not to operate.
- Ability to meter currents and voltages, as well as status of connected circuit breakers, continuously during non-Fault times. The relays can compute values, such as MW and MVAR line flows, that are sometimes used for operational purposes, such as SCADA.
- Data communications via ports that provide remote access to all of the results of Protection System monitoring, recording and measurement.
- Ability to trip or close circuit breakers and switches through the Protection System outputs, on command from remote data communications messages, or from relay front panel button requests.
- Construction from electronic components, some of which have shorter technical life or service life than electromechanical components of prior Protection System generations.

There have been significant advances in the technology behind the other components of Protection Systems. Microprocessors are now a part of battery chargers, associated communications equipment, voltage and current-measuring devices, and even the control circuitry (in the form of software-latches replacing lock-out relays, etc.).

Any Protection System component can have self-monitoring and alarming capability, not just relays. Because of this technology, extended time intervals can find their way into all components of the Protection System.

This standard also recognizes the distinct advantage of using advanced technology to justifiably defer or even eliminate traditional maintenance. Just as a hand-held calculator does not require routine testing and calibration, neither does a calculation buried in a microprocessor-based device that results in a “lock-out.” Thus, the software-latch 86 that replaces an electro-mechanical 86 does not require routine trip testing. Any trip circuitry associated with the “soft 86” would still need applicable verification activities performed, but the actual “86” does not have to be “electrically operated” or even toggled.

4. Definitions

Protection System Maintenance Program (PSMP) — An ongoing program by which Protection System, Automatic Reclosing and Sudden Pressure Relaying Components are kept in working order and proper operation of malfunctioning Components is restored. A maintenance program for a specific Component includes one or more of the following activities:

- Verify — Determine that the Component is functioning correctly.
- Monitor — Observe the routine in-service operation of the Component.
- Test — Apply signals to a Component to observe functional performance or output behavior, or to diagnose problems.
- Inspect — Detect visible signs of Component failure, reduced performance and degradation.
- Calibrate — Adjust the operating threshold or measurement accuracy of a measuring element to meet the intended performance requirement.

Automatic Reclosing – Includes the following Components:

- Reclosing relay
- Control circuitry associated with the reclosing relay.

Sudden Pressure Relaying – A system that trips an interrupting device(s) to isolate the equipment it is monitoring and includes the following Components:

- Fault pressure relay – a mechanical relay or device that detecting rapid changes in gas pressure, oil pressure, or oil flow that are indicative of faults within liquid-filled, wire-wound equipment
- Control circuitry associated with a fault pressure relay

Unresolved Maintenance Issue – A deficiency identified during a maintenance activity that causes the component to not meet the intended performance, cannot be corrected during the maintenance interval, and requires follow-up corrective action.

Segment – Components of a consistent design standard, or a particular model or type from a single manufacturer that typically share other common elements. Consistent performance is expected across the entire population of a Segment. A Segment must contain at least sixty (60) individual Components.

Component Type –

- Any one of the five specific elements of a Protection System.
- Any one of the two specific elements of Automatic Reclosing.
- Any one of the two specific elements of Sudden Pressure Relaying.

Component – Any individual discrete piece of equipment included in a Protection System, Automatic Reclosing, or Sudden Pressure Relaying.

Countable Event – A failure of a Component requiring repair or replacement, any condition discovered during the maintenance activities in Tables 1-1 through 1-5, Table 3, Tables 4-1 through 4-2, and Table 5, which requires corrective action or a Protection System Misoperation attributed to hardware failure or calibration failure. Misoperations due to product design errors, software errors, relay settings different from specified settings, Protection System Component, Automatic Reclosing or Sudden Pressure Relaying configuration or application errors are not included in Countable Events.

4.1 Frequently Asked Questions:

Why does PRC-005-X not specifically require maintenance and testing procedures, as reflected in the previous standard, PRC-005-1?

PRC-005-1 does not require detailed maintenance and testing procedures, but instead requires summaries of such procedures, and is not clear on what is actually required. PRC-005-X requires a documented maintenance program, and is focused on establishing requirements rather than prescribing methodology to meet those requirements. Between the activities identified in the Tables 1-1 through 1-5, Table 2, Table 3, and Table 4 (collectively the "Tables"), and the various components of the definition established for a "Protection System Maintenance Program," PRC-005-X establishes the activities and time basis for a Protection System Maintenance Program to a level of detail not previously required.

Please clarify what is meant by "restore" in the definition of maintenance.

The description of "restore" in the definition of a Protection System Maintenance Program addresses corrective activities necessary to assure that the component is returned to working order following the discovery of its failure or malfunction. The Maintenance Activities specified in the Tables do not present any requirements related to Restoration; R5 of the standard does require that the entity "shall demonstrate efforts to correct any identified Unresolved Maintenance Issues." Some examples of restoration (or correction of Unresolved Maintenance Issues) include, but are not limited to, replacement of capacitors in distance relays to bring them to working order; replacement of relays, or other Protection System components, to bring the Protection System to working order; upgrade of electromechanical or solid-state protective relays to microprocessor-based relays following the discovery of failed components. Restoration, as used in this context, is not to be confused with restoration rules as used in system operations. Maintenance activity necessarily includes both the detection of problems and the repairs needed to eliminate those problems. This standard does not identify all of the Protection System problems that must be detected and eliminated, rather it is the intent of this standard that an entity determines the necessary working order for their various devices, and keeps them in working order. If an equipment item is repaired or replaced, then the entity can restart the maintenance-time-interval-clock, if desired; however, the replacement of equipment does not remove any documentation requirements that would have been required to verify compliance with time-interval requirements. In other words, do not discard maintenance data that goes to verify your work.

The retention of documentation for new and/or replaced equipment is all about proving that the maintenance intervals had been in compliance. For example, a long-range plan of upgrades might lead an entity to ignore required maintenance; retaining the evidence of prior maintenance that existed before any retirements and upgrades proves compliance with the standard.

Please clarify what is meant by "…demonstrate efforts to correct an Unresolved Maintenance Issue…"; why not measure the completion of the corrective action?

Management of completion of the identified Unresolved Maintenance Issue is a complex topic that falls outside of the scope of this standard. There can be any number of supply, process and management problems that make setting repair deadlines impossible. The SDT specifically chose the phrase "demonstrate efforts to correct" (with guidance from NERC Staff) because of the concern that many more complex Unresolved Maintenance Issues might require greater than the remaining maintenance interval to resolve (and yet still be a "closed-end process"). For example, a problem might be identified on a VRLA battery during a six-month check. In instances such as one that requiring battery replacement as part of the long-term resolution, it is highly unlikely that the battery could be replaced in time to meet the six-calendar-month requirement for this maintenance activity. The SDT does not believe entities should be found in violation of a maintenance program requirement because of the inability to complete a remediation program within the original maintenance interval. The SDT does believe corrective actions should be timely, but concludes it would be impossible to postulate all possible remediation projects; and, therefore, impossible to specify bounding time frames for resolution of all possible Unresolved Maintenance Issues, or what documentation might be sufficient to provide proof that effective corrective action is being undertaken.

5. Time-Based Maintenance (TBM) Programs

Time-based maintenance is the process in which Protection System, Automatic Reclosing and Sudden Pressure Relaying Components are maintained or verified according to a time schedule. The scheduled program often calls for technicians to travel to the physical site and perform a functional test on Protection System components. However, some components of a TBM program may be conducted from a remote location - for example, tripping a circuit breaker by communicating a trip command to a microprocessor relay to determine if the entire Protection System tripping chain is able to operate the breaker. Similarly, all Protection System, and Sudden Pressure Relaying Components can have the ability to remotely conduct tests, either on-command or routinely; the running of these tests can extend the time interval between hands-on maintenance activities.

5.1 Maintenance Practices

Maintenance and testing programs often incorporate the following types of maintenance practices:

- TBM – time-based maintenance – externally prescribed maximum maintenance or testing intervals are applied for components or groups of components. The intervals may have been developed from prior experience or manufacturers' recommendations. The TBM verification interval is based on a variety of factors, including experience of the particular asset owner, collective experiences of several asset owners who are members of a country or regional council, etc. The maintenance intervals are fixed and may range in number of months or in years.

  TBM can include review of recent power system events near the particular terminal. Operating records may verify that some portion of the Protection System has operated correctly since the last test occurred. If specific protection scheme components have demonstrated correct performance within specifications, the maintenance test time clock can be reset for those components.

- PBM – Performance-Based Maintenance - intervals are established based on analytical or historical results of TBM failure rates on a statistically significant population of similar components. Some level of TBM is generally followed. Statistical analyses accompanied by adjustments to maintenance intervals are used to justify continued use of PBM-developed extended intervals when test failures or in-service failures occur infrequently.

- CBM – condition-based maintenance – continuously or frequently reported results from non-disruptive self-monitoring of components demonstrate operational status as those components remain in service. Whatever is verified by CBM does not require manual testing, but taking advantage of this requires precise technical focus on exactly what parts are included as part of the self-diagnostics. While the term "Condition-Based-Maintenance" (CBM) is no longer used within the standard itself, it is important to note that the concepts of CBM are a part of the standard (in the form of extended time intervals through status-monitoring). These extended time intervals are only allowed (in the absence of PBM) if the condition of the device is monitored (CBM). As a consequence of the "monitored-basis-time-intervals" existing within the standard, the explanatory

discussions within this Supplementary Reference concerned with CBM will remain in this reference and are discussed as CBM.

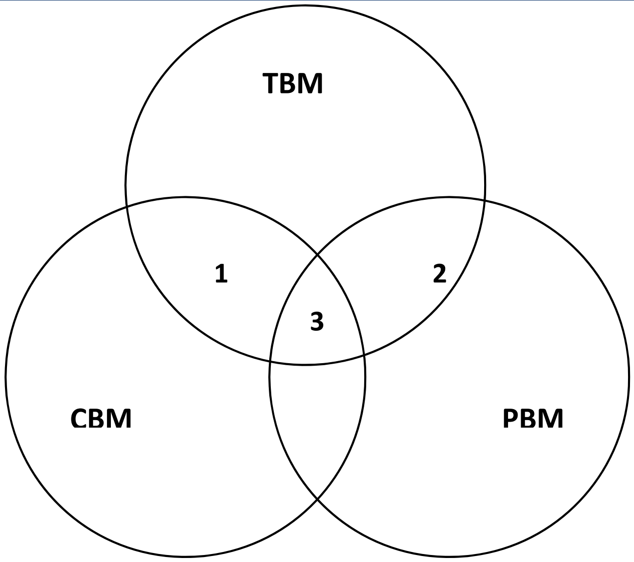
Microprocessor-based Protection System or Automatic Reclosing Components that perform continuous self-monitoring verify correct operation of most components within the device. Self-monitoring capabilities may include battery continuity, float voltages, unintentional grounds, the ac signal inputs to a relay, analog measuring circuits, processors and memory for measurement, protection, and data communications, trip circuit monitoring, and protection or data communications signals (and many, many more measurements). For those conditions, failure of a self-monitoring routine generates an alarm and may inhibit operation to avoid false trips. When internal components, such as critical output relay contacts, are not equipped with self-monitoring, they can be manually tested. The method of testing may be local or remote, or through inherent performance of the scheme during a system event.

The TBM is the overarching maintenance process of which the other types are subsets. Unlike TBM, PBM intervals are adjusted based on good or bad experiences. The CBM verification intervals can be hours, or even milliseconds between non-disruptive self-monitoring checks within or around components as they remain in service.

TBM, PBM, and CBM can be combined for individual components, or within a complete Protection System. The following diagram illustrates the relationship between various types of maintenance practices described in this section. In the Venn diagram, the overlapping regions show the relationship of TBM with PBM historical information and the inherent continuous monitoring offered through CBM.

This figure shows:

- Region 1: The TBM intervals that are increased based on known reported operational condition of individual components that are monitoring themselves.
- Region 2: The TBM intervals that are adjusted up or down based on results of analysis of maintenance history of statistically significant population of similar products that have been subject to TBM.
- Region 3: Optimal TBM intervals based on regions 1 and 2.



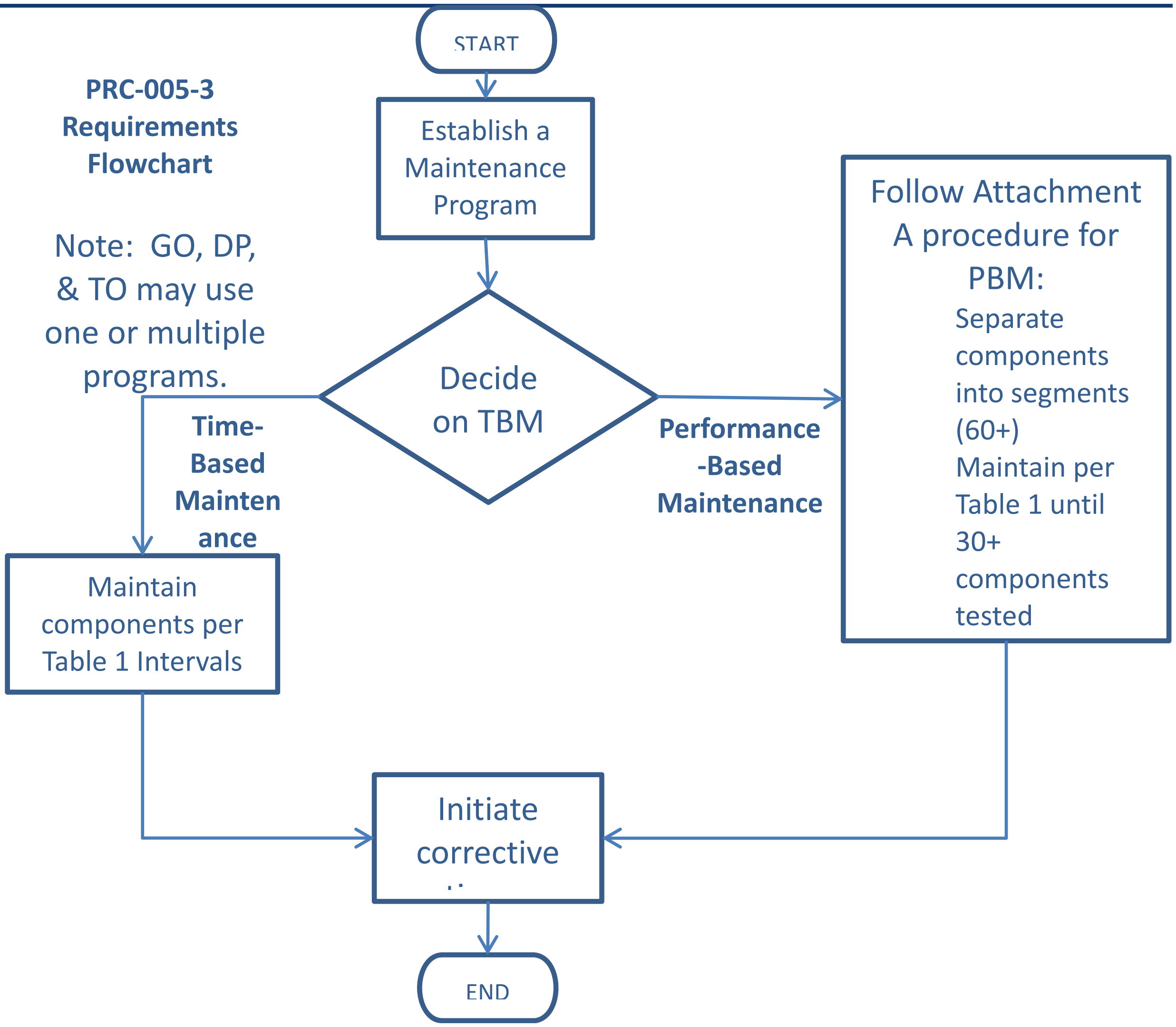
Relationship of time-based maintenance types

5.1.1 Frequently Asked Questions:

The standard seems very complicated, and is difficult to understand. Can it be simplified?

Because the standard is establishing parameters for condition-based Maintenance (R1) and Performance-Based Maintenance (R2), in addition to simple time-based Maintenance, it does appear to be complicated. At its simplest, an entity needs to ONLY perform time-based maintenance according to the unmonitored rows of the Tables. If an entity then wishes to take advantage of monitoring on its Protection System components and its available lengthened time intervals, then it may, as long as the component has the listed monitoring attributes. If an entity wishes to use historical performance of its Protection System components to perform Performance-Based Maintenance, then R2 applies.

Please see the following diagram, which provides a “flow chart” of the standard.



We have an electromechanical (unmonitored) relay that has a trip output to a lockout relay (unmonitored) which trips our transformer off-line by tripping the transformer's high-side and low-side circuit breakers. What testing must be done for this system?

This system is made up of components that are all unmonitored. Assuming a time-based Protection System Maintenance Program schedule (as opposed to a Performance-Based maintenance program), each component must be maintained per the most frequent hands-on activities listed in the Tables.

5.2 Extending Time-Based Maintenance

All maintenance is fundamentally time-based. Default time-based intervals are commonly established to assure proper functioning of each component of the Protection System, when data on the reliability of the components is not available other than observations from time-based maintenance. The following factors may influence the established default intervals:

- If continuous indication of the functional condition of a component is available (from relays or chargers or any self-monitoring device), then the intervals may be extended, or manual testing may be eliminated. This is referred to as condition-based maintenance or

CBM. CBM is valid only for precisely the components subject to monitoring. In the case of microprocessor-based relays, self-monitoring may not include automated diagnostics of every component within a microprocessor.

- Previous maintenance history for a group of components of a common type may indicate that the maintenance intervals can be extended, while still achieving the desired level of performance. This is referred to as Performance-Based Maintenance, or PBM. It is also sometimes referred to as reliability-centered maintenance, or RCM; but PBM is used in this document.
- Observed proper operation of a component may be regarded as a maintenance verification of the respective component or element in a microprocessor-based device. For such an observation, the maintenance interval may be reset only to the degree that can be verified by data available on the operation. For example, the trip of an electromechanical relay for a Fault verifies the trip contact and trip path, but only through the relays in series that actually operated; one operation of this relay cannot verify correct calibration.

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. The improper application of test signals may cause failure of a component. For example, in electromechanical overcurrent relays, test currents have been known to destroy convolution springs.

In addition, maintenance usually takes the component out of service, during which time it is not able to perform its function. Cutout switch failures, or failure to restore switch position, commonly lead to protection failures.

5.2.1 Frequently Asked Questions:

If I show the protective device out of service while it is being repaired, then can I add it back as a new protective device when it returns? If not, my relay testing history would show that I was out of compliance for the last maintenance cycle.

The maintenance and testing requirements (R5) (in essence) state "…shall demonstrate efforts to correct any identified Unresolved Maintenance Issues." The type of corrective activity is not stated; however it could include repairs or replacements.

Your documentation requirements will increase, of course, to demonstrate that your device tested bad and had corrective actions initiated. Your regional entity could very well ask for documentation showing status of your corrective actions.

6. Condition-Based Maintenance (CBM) Programs

Condition-based maintenance is the process of gathering and monitoring the information available from modern microprocessor-based relays and other intelligent electronic devices (IEDs) that monitor Protection System or Automatic Reclosing elements. These devices generate monitoring information during normal operation, and the information can be assessed at a convenient location remote from the substation. The information from these relays and IEDs is divided into two basic types:

1. Information can come from background self-monitoring processes, programmed by the manufacturer, or by the user in device logic settings. The results are presented by alarm contacts or points, front panel indications, and by data communications messages.
2. Information can come from event logs, captured files, and/or oscillographic records for Faults and Disturbances, metered values, and binary input status reports. Some of these are available on the device front panel display, but may be available via data communications ports. Large files of Fault information can only be retrieved via data communications. These results comprise a mass of data that must be further analyzed for evidence of the operational condition of the Protection System.

Using these two types of information, the user can develop an effective maintenance program carried out mostly from a central location remote from the substation. This approach offers the following advantages:

Non-invasive Maintenance: The system is kept in its normal operating state, without human intervention for checking. This reduces risk of damage, or risk of leaving the system in an inoperable state after a manual test. Experience has shown that keeping human hands away from equipment known to be working correctly enhances reliability.

Virtually Continuous Monitoring: CBM will report many hardware failure problems for repair within seconds or minutes of when they happen. This reduces the percentage of problems that are discovered through incorrect relaying performance. By contrast, a hardware failure discovered by TBM may have been there for much of the time interval between tests, and there is a good chance that some devices will show health problems by incorrect operation before being caught in the next test round. The frequent or continuous nature of CBM makes the effective verification interval far shorter than any required TBM maximum interval. To use the extended time intervals available through Condition Based Maintenance, simply look for the rows in the Tables that refer to monitored items.

6.1 Frequently Asked Questions:

My microprocessor relays and dc circuit alarms are contained on relay panels in a 24-hour attended control room. Does this qualify as an extended time interval condition-based (monitored) system?

Yes, provided the station attendant (plant operator, etc.) monitors the alarms and other indications (comparable to the monitoring attributes) and reports them within the given time limits that are stated in the criteria of the Tables.

When documenting the basis for inclusion of components into the appropriate levels of monitoring, as per Requirement R1 (Part 1.4) of the standard, is it necessary to provide this documentation about the device by listing of every component and the specific monitoring attributes of each device?

No. While maintaining this documentation on the device level would certainly be permissible, it is not necessary. Global statements can be made to document appropriate levels of monitoring for the entire population of a component type or portion thereof.

For example, it would be permissible to document the conclusion that all BES substation dc supply battery chargers are monitored by stating the following within the program description:

> "All substation dc supply battery chargers are considered monitored and subject to the rows for monitored equipment of Table 1-4 requirements, as all substation dc supply battery chargers are equipped with dc voltage alarms and ground detection alarms that are sent to the manned control center."

Similarly, it would be acceptable to use a combination of a global statement and a device-level list of exclusions. Example:

> "Except as noted below, all substation dc supply battery chargers are considered monitored and subject to the rows for monitored equipment of Table 1-4 requirements, as all substation dc supply battery chargers are equipped with dc voltage alarms and ground detection alarms that are sent to the manned control center. The dc supply battery chargers of Substation X, Substation Y, and Substation Z are considered unmonitored and subject to the rows for unmonitored equipment in Table 1-4 requirements, as they are not equipped with ground detection capability."

Regardless whether this documentation is provided by device listing of monitoring attributes, by global statements of the monitoring attributes of an entire population of component types, or by some combination of these methods, it should be noted that auditors may request supporting drawings or other documentation necessary to validate the inclusion of the device(s) within the appropriate level of monitoring. This supporting background information need not be maintained within the program document structure, but should be retrievable if requested by an auditor.

7. Time-Based Versus Condition-Based Maintenance

Time-based and condition-based (or monitored) maintenance programs are both acceptable, if implemented according to technically sound requirements. Practical programs can employ a *combination of time-based and condition-based maintenance.* The standard requirements introduce the concept of optionally using condition monitoring as a documented element of a maintenance program.

The Federal Energy Regulatory Commission (FERC), in its Order Number 693 Final Rule, dated March 16, 2007 (18 CFR Part 40, Docket No. RM06-16-000) on Mandatory Reliability Standards for the Bulk-Power System, directed NERC to submit a modification to PRC-005-1b that includes a requirement that maintenance and testing of a Protection System must be carried out within a maximum allowable interval that is appropriate to the type of the Protection System and its impact on the reliability of the Bulk Power System. Accordingly, this Supplementary Reference Paper refers to the specific maximum allowable intervals in PRC-005-X. The defined time limits allow for longer time intervals if the maintained component is monitored.

A key feature of condition-based monitoring is that it effectively reduces the time delay between the moment of a protection failure and time the Protection System or Automatic Reclosing owner knows about it, for the monitored segments of the Protection System. In some cases, the verification is practically continuous - the time interval between verifications is minutes or seconds. Thus, technically sound, condition-based verification, meets the verification requirements of the FERC order even more effectively than the strictly time-based tests of the same system components.

The result is that:

This NERC standard permits utilities to use a technically sound approach and to take advantage of remote monitoring, data analysis, and control capabilities of modern Protection System and Automatic Reclosing Components to reduce the need for periodic site visits and invasive testing of components by on-site technicians. This periodic testing must be conducted within the maximum time intervals specified in the Tables of PRC-005-X.

7.1 Frequently Asked Questions:

What is a Calendar Year?

Calendar Year - January 1 through December 31 of any year. As an example, if an event occurred on June 17, 2009 and is on a "One Calendar Year Interval," the next event would have to occur on or before December 31, 2010.

Please provide an example of "4 Calendar Months".

If a maintenance activity is described as being needed every four Calendar Months then it is performed in a (given) month and due again four months later. For example a battery bank is inspected in month number 1 then it is due again before the end of the month number5. And specifically consider that you perform your battery inspection on January 3, 2010 then it must be inspected again before the end of May. Another example could be that a four-month inspection

was performed in January is due in May, but if performed in March (instead of May) would still be due four months later therefore the activity is due again July. Basically every "four Calendar Months" means to add four months from the last time the activity was performed.

Please provide an example of the unmonitored versus other levels of monitoring available?

An unmonitored Protection System has no monitoring and alarm circuits on the Protection System components. A Protection System component that has monitoring attributes but no alarm output connected is considered to be unmonitored.

A monitored Protection System or an individual monitored component of a Protection System has monitoring and alarm circuits on the Protection System components. The alarm circuits must alert, within 24 hours, a location wherein corrective action can be initiated. This location might be, but is not limited to, an Operations Center, Dispatch Office, Maintenance Center or even a portable SCADA system.

There can be a combination of monitored and unmonitored Protection Systems within any given scheme, substation or plant; there can also be a combination of monitored and unmonitored components within any given Protection System.

Example #1: A combination of monitored and unmonitored components within a given Protection System might be:

- A microprocessor relay with an internal alarm connected to SCADA to alert 24-hr staffed operations center; it has internal self-diagnosis and alarming. (monitored)
- Instrumentation transformers, with no monitoring, connected as inputs to that relay. (unmonitored)
- A vented Lead-Acid battery with a low voltage alarm for the station dc supply voltage and an unintentional grounds detection alarm connected to SCADA. (monitoring varies)
- A circuit breaker with a trip coil, and the trip circuit is not monitored. (unmonitored)

Given the particular components and conditions, and using Table 1 and Table 2, the particular components have maximum activity intervals of:

Every four calendar months, inspect:

- Electrolyte level (station dc supply voltage and unintentional ground detection is being maintained more frequently by the monitoring system).

Every 18 calendar months, verify/inspect the following:

- Battery bank ohmic values to station battery baseline (if performance tests are not opted)
- Battery charger float voltage
- Battery rack integrity
- Cell condition of all individual battery cells (where visible)
- Battery continuity
- Battery terminal connection resistance

- Battery cell-to-cell resistance (where available to measure)

<u>Every six calendar years</u>, perform/verify the following:

- Battery performance test (if internal ohmic tests or other measurements indicative of battery performance are not opted)
- Verify that each trip coil is able to operate the circuit breaker, interrupting device, or mitigating device
- For electromechanical lock-out relays, electrical operation of electromechanical trip

<u>Every 12 calendar years</u>, verify the following:

- Microprocessor relay settings are as specified
- Operation of the microprocessor's relay inputs and outputs that are essential to proper functioning of the Protection System
- Acceptable measurement of power System input values seen by the microprocessor protective relay
- Verify that current and voltage signal values are provided to the protective relays
- Protection System component monitoring for the battery system signals are conveyed to a location where corrective action can be initiated
- The microprocessor relay alarm signals are conveyed to a location where corrective action can be initiated
- Verify all trip paths in the control circuitry associated with protective functions through the trip coil(s) of the circuit breakers or other interrupting devices
- Auxiliary outputs that are in the trip path shall be maintained as detailed in Table 1-5 of the standard under the 'Unmonitored Control Circuitry Associated with Protective Functions" section'
- Auxiliary outputs not in a trip path (i.e., annunciation or DME input) are not required, by this standard, to be checked

Example #2: A combination of monitored and unmonitored components within a given Protection System might be:

- A microprocessor relay with integral alarm that is not connected to SCADA. (unmonitored)
- Current and voltage signal values, with no monitoring, connected as inputs to that relay. (unmonitored)
- A vented lead-acid battery with a low voltage alarm for the station dc supply voltage and an unintentional grounds detection alarm connected to SCADA. (monitoring varies)
- A circuit breaker with a trip coil, with no circuits monitored. (unmonitored)

Given the particular components and conditions, and using the Table 1 (Maximum Allowable Testing Intervals and Maintenance Activities) and Table 2 (Alarming Paths and Monitoring), the particular components have maximum activity intervals of:

Every four calendar months, inspect:

- Electrolyte level (station dc supply voltage and unintentional ground detection is being maintained more frequently by the monitoring system)

Every 18 calendar months, verify/inspect the following:

- Battery bank trending of ohmic values or other measurements indicative of battery performance to station battery baseline (if performance tests are not opted)
- Battery charger float voltage
- Battery rack integrity
- Cell condition of all individual battery cells (where visible)
- Battery continuity
- Battery terminal connection resistance
- Battery cell-to-cell resistance (where available to measure)

Every six calendar years, verify/perform the following:

- Verify operation of the relay inputs and outputs that are essential to proper functioning of the Protection System
- Verify acceptable measurement of power system input values as seen by the relays
- Verify that each trip coil is able to operate the circuit breaker, interrupting device, or mitigating device
- For electromechanical lock-out relays, electrical operation of electromechanical trip
- Battery performance test (if internal ohmic tests are not opted)

Every 12 calendar years, verify the following:

- Current and voltage signal values are provided to the protective relays
- Protection System component monitoring for the battery system signals are conveyed to a location where corrective action can be initiated
- All trip paths in the control circuitry associated with protective functions through the trip coil(s) of the circuit breakers or other interrupting devices
- Auxiliary outputs that are in the trip path shall be maintained, as detailed in Table 1-5 of the standard under the Unmonitored Control Circuitry Associated with Protective Functions" section
- Auxiliary outputs not in a trip path (i.e., annunciation or DME input) are not required, by this standard, to be checked

Example #3: A combination of monitored and unmonitored components within a given Protection System might be:

- A microprocessor relay with alarm connected to SCADA to alert 24-hr staffed operations center; it has internal self-diagnosis and alarms. (monitored)
- Current and voltage signal values, with monitoring, connected as inputs to that relay (monitored)

- Vented Lead-Acid battery without any alarms connected to SCADA (unmonitored)
- Circuit breaker with a trip coil, with no circuits monitored (unmonitored)

Given the particular components, conditions, and using the Table 1 (Maximum Allowable Testing Intervals and Maintenance Activities) and Table 2 (Alarming Paths and Monitoring), the particular components shall have maximum activity intervals of:

Every four calendar months, verify/inspect the following:

- Station dc supply voltage
- For unintentional grounds
- Electrolyte level

Every 18 calendar months, verify/inspect the following:

- Battery bank trending of ohmic values or other measurements indicative of battery performance to station battery baseline (if performance tests are not opted)
- Battery charger float voltage
- Battery rack integrity
- Battery continuity
- Battery terminal connection resistance
- Battery cell-to-cell resistance (where available to measure)
- Condition of all individual battery cells (where visible)

Every six calendar years, perform/verify the following:

- Battery performance test (if internal ohmic tests or other measurements indicative of battery performance are not opted)
- Verify that each trip coil is able to operate the circuit breaker, interrupting device, or mitigating device
- For electromechanical lock-out relays, electrical operation of electromechanical trip

Every 12 calendar years, verify the following:

- The microprocessor relay alarm signals are conveyed to a location where corrective action can be taken
- Microprocessor relay settings are as specified
- Operation of the microprocessor’s relay inputs and outputs that are essential to proper functioning of the Protection System
- Acceptable measurement of power system input values seen by the microprocessor protective relay
- Verify all trip paths in the control circuitry associated with protective functions through the trip coil(s) of the circuit breakers or other interrupting devices

- Auxiliary outputs that are in the trip path shall be maintained, as detailed in Table 1-5 of the standard under the Unmonitored Control Circuitry Associated with Protective Functions section
- Auxiliary outputs not in a trip path (i.e. annunciation or DME input) are not required, by this standard, to be checked

Why do components have different maintenance activities and intervals if they are monitored?

The intent behind different activities and intervals for monitored equipment is to allow less frequent manual intervention when more information is known about the condition of Protection System components. Condition-Based Maintenance is a valuable asset to improve reliability.

Can all components in a Protection System be monitored?

No. For some components in a Protection System, monitoring will not be relevant. For example, a battery will always need some kind of inspection.

We have a 30-year-old oil circuit breaker with a red indicating lamp on the substation relay panel that is illuminated only if there is continuity through the breaker trip coil. There is no SCADA monitor or relay monitor of this trip coil. The line protection relay package that trips this circuit breaker is a microprocessor relay that has an integral alarm relay that will assert on a number of conditions that includes a loss of power to the relay. This alarm contact connects to our SCADA system and alerts our 24-hour operations center of relay trouble when the alarm contact closes. This microprocessor relay trips the circuit breaker only and does not monitor trip coil continuity or other things such as trip current. Are the components monitored or not? How often must I perform maintenance?

The protective relay is monitored and can be maintained every 12 years, or when an Unresolved Maintenance Issue arises. The control circuitry can be maintained every 12 years. The circuit breaker trip coil(s) has to be electrically operated at least once every six years.

What is a mitigating device?

A mitigating device is the device that acts to respond as directed by a Special Protection System. It may be a breaker, valve, distributed control system, or any variety of other devices. This response may include tripping, closing, or other control actions.

8. Maximum Allowable Verification Intervals

The maximum allowable testing intervals and maintenance activities show how CBM with newer device types can reduce the need for many of the tests and site visits that older Protection System components require. As explained below, there are some sections of the Protection System that monitoring or data analysis may not verify. Verifying these sections of the Protection System or Automatic Reclosing requires some persistent TBM activity in the maintenance program. However, some of this TBM can be carried out remotely - for example, exercising a circuit breaker through the relay tripping circuits using the relay remote control capabilities can be used to verify function of one tripping path and proper trip coil operation, if there has been no Fault or routine operation to demonstrate performance of relay tripping circuits.

8.1 Maintenance Tests

Periodic maintenance testing is performed to ensure that the protection and control system is operating correctly after a time period of field installation. These tests may be used to ensure that individual components are still operating within acceptable performance parameters - this type of test is needed for components susceptible to degraded or changing characteristics due to aging and wear. Full system performance tests may be used to confirm that the total Protection System functions from measurement of power system values, to properly identifying Fault characteristics, to the operation of the interrupting devices.

8.1.1 Table of Maximum Allowable Verification Intervals

Table 1 (collectively known as Table 1, individually called out as Tables 1-1 through 1-5), Table 2, Table 3, Table 4-1 through Table 4-2, and Table 5 in the standard specify maximum allowable verification intervals for various generations of Protection Systems, Automatic Reclosing and Sudden Pressure Relaying and categories of equipment that comprise these systems. The right column indicates maintenance activities required for each category.

The types of components are illustrated in Figures 1 and 2 at the end of this paper. Figure 1 shows an example of telecommunications-assisted transmission Protection System comprising substation equipment at each terminal and a telecommunications channel for relaying between the two substations. Figure 2 shows an example of a generation Protection System. The various sub-systems of a Protection System that need to be verified are shown.

Non-distributed UFLS, UVLS, and SPS are additional categories of Table 1 that are not illustrated in these figures. Non-distributed UFLS, UVLS and SPS all use identical equipment as Protection Systems in the performance of their functions; and, therefore, have the same maintenance needs.

Distributed UFLS and UVLS Systems, which use local sensing on the distribution System and trip co-located non-BES interrupting devices, are addressed in Table 3 with reduced maintenance activities.

While it is easy to associate protective relays to multiple levels of monitoring, it is also true that most of the components that can make up a Protection System can also have technological advancements that place them into higher levels of monitoring.

To use the Maintenance Activities and Intervals Tables from PRC-005-X:

- First find the Table associated with your component. The tables are arranged in the order of mention in the definition of Protection System;
  - Table 1-1 is for protective relays,
  - Table 1-2 is for the associated communications systems,
  - Table 1-3 is for current and voltage sensing devices,
  - Table 1-4 is for station dc supply and
  - Table 1-5 is for control circuits.
  - Table 2, is for alarms; this was broken out to simplify the other tables.
  - Table 3 is for components which make-up distributed UFLS and UVLS Systems.
  - Table 4 is for Automatic Reclosing.
  - Table 5 is for Sudden Pressure Relaying.
- Next look within that table for your device and its degree of monitoring. The Tables have different hands-on maintenance activities prescribed depending upon the degree to which you monitor your equipment. Find the maintenance activity that applies to the monitoring level that you have on your piece of equipment.
- This Maintenance activity is the minimum maintenance activity that must be documented.
- If your Performance-Based Maintenance (PBM) plan requires <u>more activities,</u> then you must perform and document to this higher standard. (Note that this does not apply unless you utilize PBM.)
- After the maintenance activity is known, check the maximum maintenance interval; this time is the maximum time allowed between hands-on maintenance activity cycles of this component.
- If your Performance-Based Maintenance plan requires activities <u>more often</u> than the Tables maximum, then you must perform and document those activities to your more stringent standard. (Note that this does not apply unless you utilize PBM.)
- Any given component of a Protection System can be determined to have a degree of monitoring that may be different from another component within that same Protection System. For example, in a given Protection System it is possible for an entity to have a monitored protective relay and an unmonitored associated communications system; this combination would require hands-on maintenance activity on the relay at least once every 12 years and attention paid to the communications system as often as every four months.
- An entity does not have to utilize the extended time intervals made available by this use of condition-based monitoring. An easy choice to make is to simply utilize the unmonitored level of maintenance made available in each of the Tables. While the maintenance activities resulting from this choice would require more maintenance man-hours, the maintenance requirements may be simpler to document and the resulting maintenance plans may be easier to create.

For each Protection System Component, Table 1 shows maximum allowable testing intervals for the various degrees of monitoring. For each Automatic Reclosing Component, Table 4 shows maximum allowable testing intervals for the various degrees of monitoring. These degrees of monitoring, or levels, range from the legacy unmonitored through a system that is more comprehensively monitored.

It has been noted here that an entity may have a PSMP that is more stringent than PRC-005-X. There may be any number of reasons that an entity chooses a more stringent plan than the minimums prescribed within PRC-005-X, most notable of which is an entity using performance based maintenance methodology. If an entity has a Performance-Based Maintenance program, then that plan must be followed, even if the plan proves to be more stringent than the minimums laid out in the Tables.

8.1.2 Additional Notes for Tables 1-1 through 1-5, Table 3, and Table 4

1. For electromechanical relays, adjustment is required to bring measurement accuracy within the tolerance needed by the asset owner. Microprocessor relays with no remote monitoring of alarm contacts, etc., are unmonitored relays and need to be verified within the Table interval as other unmonitored relays but may be verified as functional by means other than testing by simulated inputs.

2. Microprocessor relays typically are specified by manufacturers as not requiring calibration, but acceptable measurement of power system input values must be verified (verification of the Analog to Digital [A/D] converters) within the Table intervals. The integrity of the digital inputs and outputs that are used as protective functions must be verified within the Table intervals.

3. Any Phasor Measurement Unit (PMU) function whose output is used in a Protection System or SPS (as opposed to a monitoring task) must be verified as a component in a Protection System.

4. In addition to verifying the circuitry that supplies dc to the Protection System, the owner must maintain the station dc supply. The most widespread station dc supply is the station battery and charger. Unlike most Protection System components, physical inspection of station batteries for signs of component failure, reduced performance, and degradation are required to ensure that the station battery is reliable enough to deliver dc power when required. IEEE Standards 450, 1188, and 1106 for vented lead-acid, valve-regulated lead-acid, and nickel-cadmium batteries, respectively (which are the most commonly used substation batteries on the NERC BES) have been developed as an important reference source of maintenance recommendations. The Protection System owner might want to follow the guidelines in the applicable IEEE recommended practices for battery maintenance and testing, especially if the battery in question is used for application requirements in addition to the protection and control demands covered under this standard. However, the Standard Drafting Team has tailored the battery maintenance and testing guidelines in PRC-005-X for the Protection System owner which are application specific for the BES Facilities. While the IEEE recommendations are all encompassing, PRC-005-X is a more economical approach while addressing the reliability requirements of the BES.

5. Aggregated small entities might distribute the testing of the population of UFLS/UVLS systems, and large entities will usually maintain a portion of these systems in any given year. Additionally, if relatively small quantities of such systems do not perform properly, it will not affect the integrity of the overall program. Thus, these distributed systems have decreased requirements as compared to other Protection Systems.

6. Voltage & current sensing device circuit input connections to the Protection System relays can be verified by (but not limited to) comparison of measured values on live circuits or by using test currents and voltages on equipment out of service for maintenance. The verification process can be automated or manual. The values should be verified to be as expected (phase value and phase relationships are both equally important to verify).

7. "End-to-end test," as used in this Supplementary Reference, is any testing procedure that creates a remote input to the local communications-assisted trip scheme. While this can be interpreted as a GPS-type functional test, it is not limited to testing via GPS. Any remote scheme manipulation that can cause action at the local trip path can be used to functionally-test the dc control circuitry. A documented Real-time trip of any given trip path is acceptable in lieu of a functional trip test. It is possible, with sufficient monitoring, to be able to verify each and every parallel trip path that participated in any given dc control circuit trip. Or another possible solution is that a single trip path from a single monitored relay can be verified to be the trip path that successfully tripped during a Real-time operation. The variations are only limited by the degree of engineering and monitoring that an entity desires to pursue.

8. A/D verification may use relay front panel value displays, or values gathered via data communications. Groupings of other measurements (such as vector summation of bus feeder currents) can be used for comparison if calibration requirements assure acceptable measurement of power system input values.

9. Notes 1-8 attempt to describe some testing activities; they do not represent the only methods to achieve these activities, but rather some possible methods. Technological advances, ingenuity and/or industry accepted techniques can all be used to satisfy maintenance activity requirements; the standard is technology- and method-neutral in most cases.

8.1.3 Frequently Asked Questions:

What is meant by "Verify that settings are as specified" maintenance activity in Table 1-1?

Verification of settings is an activity directed mostly towards microprocessor- based relays. For relay maintenance departments that choose to test microprocessor-based relays in the same manner as electromechanical relays are tested, the testing process sometimes requires that some specific functions be disabled. Later tests might enable the functions previously disabled, but perhaps still other functions or logic statements were then masked out. It is imperative that, when the relay is placed into service, the settings in the relay be the settings that were intended to be in that relay or as the standard states "…settings are as specified."

Many of the microprocessor- based relays available today have software tools which provide this functionality and generate reports for this purpose.

For evidence or documentation of this requirement, a simple recorded acknowledgement that the settings were checked to be as specified is sufficient.

The drafting team was careful not to require "…that the relay settings be correct…" because it was believed that this might then place a burden of proof that the specified settings would result in the correct intended operation of the interrupting device. While that is a noble intention, the measurable proof of such a requirement is immense. The intent is that settings of the component be as specified at the conclusion of maintenance activities, whether those settings may have "drifted" since the prior maintenance or whether changes were made as part of the testing process.

Are electromechanical relays included in the "Verify that settings are as specified" maintenance activity in Table 1-1?

Verification of settings is an activity directed towards the application of protection related functions of microprocessor based relays. Electromechanical relays require calibration verification by voltage and/or current injection; and, thus, the settings are verified during calibration activity. In the example of a time-overcurrent relay, a minor deviation in time dial, versus the settings, may be acceptable, as long as the relay calibration is within accepted tolerances at the injected current amplitudes. A major deviation may require further investigation, as it could indicate a problem with the relay or an incorrect relay style for the application.

The verification of phase current and voltage measurements by comparison to other quantities seems reasonable. How, though, can I verify residual or neutral currents, or 3V0 voltages, by comparison, when my system is closely balanced?

Since these inputs are verified at commissioning, maintenance verification requires ensuring that phase quantities are as expected and that 3IO and 3VO quantities appear equal to or close to 0.

These quantities also may be verified by use of oscillographic records for connected microprocessor relays as recorded during system Disturbances. Such records may compare to similar values recorded at other locations by other microprocessor relays for the same event, or compared to expected values (from short circuit studies) for known Fault locations.

What does this Standard require for testing an auxiliary tripping relay?

Table 1 and Table 3 requires that a trip test must verify that the auxiliary tripping relay(s) and/or lockout relay(s) which are directly in a trip path from the protective relay to the interrupting device trip coil operate(s) electrically. Auxiliary outputs not in a trip path (i.e. annunciation or DME input) are not required, by this standard, to be checked.

Do I have to perform a full end-to-end test of a Special Protection System?

No. All portions of the SPS need to be maintained, and the portions must overlap, but the overall SPS does not need to have a single end-to-end test. In other words it may be tested in piecemeal fashion provided all of the pieces are verified.

What about SPS interfaces between different entities or owners?

As in all of the Protection System requirements, SPS segments can be tested individually, thus minimizing the need to accommodate complex maintenance schedules.

What do I have to do if I am using a phasor measurement unit (PMU) as part of a Protection System or Special Protection System?

Any Phasor Measurement Unit (PMU) function whose output is used in a Protection System or Special Protection System (as opposed to a monitoring task) must be verified as a component in a Protection System.

How do I maintain a Special Protection System or relay sensing for non-distributed UFLS or UVLS Systems?

Since components of the SPS, UFLS and UVLS are the same types of components as those in Protection Systems, then these components should be maintained like similar components used for other Protection System functions. In many cases the devices for SPS, UFLS and UVLS are also used for other protective functions. The same maintenance activities apply with the exception that distributed systems (UFLS and UVLS) have fewer dc supply and control circuitry maintenance activity requirements.

For the testing of the output action, verification may be by breaker tripping, but may be verified in overlapping segments. For example, an SPS that trips a remote circuit breaker might be tested by testing the various parts of the scheme in overlapping segments. Another method is to document the Real-time tripping of an SPS scheme should that occur. Forced trip tests of circuit breakers (etc.) that are a part of distributed UFLS or UVLS schemes are not required.

The established maximum allowable intervals do not align well with the scheduled outages for my power plant. Can I extend the maintenance to the next scheduled outage following the established maximum interval?

No. You must complete your maintenance within the established maximum allowable intervals in order to be compliant. You will need to schedule your maintenance during available outages to complete your maintenance as required, even if it means that you may do protective relay maintenance more frequently than the maximum allowable intervals. The maintenance intervals were selected with typical plant outages, among other things, in mind.

If I am unable to complete the maintenance, as required, due to a major natural disaster (hurricane, earthquake, etc.), how will this affect my compliance with this standard?

The Sanction Guidelines of the North American Electric Reliability Corporation, effective January 15, 2008, provides that the Compliance Monitor will consider extenuating circumstances when considering any sanctions.

What if my observed testing results show a high incidence of out-of-tolerance relays; or, even worse, I am experiencing numerous relay Misoperations due to the relays being out-of-tolerance?

The established maximum time intervals are mandatory only as a not-to-exceed limitation. The establishment of a maximum is measurable. But any entity can choose to test some or all of their Protection System components more frequently (or to express it differently, exceed the minimum requirements of the standard). Particularly if you find that the maximum intervals in the standard do not achieve your expected level of performance, it is understandable that you

would maintain the related equipment more frequently. A high incidence of relay Misoperations is in no one's best interest.

We believe that the four-month interval between inspections is unneccessary. Why can we not perform these inspections twice per year?

The Standard Drafting Team, through the comment process, has discovered that routine monthly inspections are not the norm. To align routine station inspections with other important inspections, the four-month interval was chosen. In lieu of station visits, many activities can be accomplished with automated monitoring and alarming.

Our maintenance plan calls for us to perform routine protective relay tests every 3 years. If we are unable to achieve this schedule, but we are able to complete the procedures in less than the maximum time interval ,then are we in or out of compliance?

According to R3, if you have a time-based maintenance program, then you will be in violation of the standard only if you exceed the maximum maintenance intervals prescribed in the Tables. According to R4, if your device in question is part of a Performance-Based Maintenance program, then you will be in violation of the standard if you fail to meet your PSMP, even if you do not exceed the maximum maintenance intervals prescribed in the Tables. The intervals in the Tables are associated with TBM and CBM; Attachment A is associated with PBM.

Please provide a sample list of devices or systems that must be verified in a generator, generator step-up transformer, generator connected station service or generator connected excitation transformer to meet the requirements of this maintenance standard.

Examples of typical devices and systems that may directly trip the generator, or trip through a lockout relay, may include, but are not necessarily limited to:

- Fault protective functions, including distance functions, voltage-restrained overcurrent functions, or voltage-controlled overcurrent functions
- Loss-of-field relays
- Volts-per-hertz relays
- Negative sequence overcurrent relays
- Over voltage and under voltage protection relays
- Stator-ground relays
- Communications-based Protection Systems such as transfer-trip systems
- Generator differential relays
- Reverse power relays
- Frequency relays
- Out-of-step relays
- Inadvertent energization protection

- Breaker failure protection

For generator step-up, generator-connected station service transformers, or generator connected excitation transformers, operation of any of the following associated protective relays frequently would result in a trip of the generating unit; and, as such, would be included in the program:

- Transformer differential relays
- Neutral overcurrent relay
- Phase overcurrent relays

Relays which trip breakers serving station auxiliary Loads such as pumps, fans, or fuel handling equipment, etc., need not be included in the program, even if the loss of the those Loads could result in a trip of the generating unit. Furthermore, relays which provide protection to secondary unit substation (SUS) or low switchgear transformers and relays protecting other downstream plant electrical distribution system components are not included in the scope of this program, even if a trip of these devices might eventually result in a trip of the generating unit. For example, a thermal overcurrent trip on the motor of a coal-conveyor belt could eventually lead to the tripping of the generator, but it does not cause the trip.

In the case where a plant does not have a generator connected station service transformer such that it is normally fed from a system connected station service transformer, is it still the drafting team's intent to exclude the Protection Systems for these system connected auxiliary transformers from scope even when the loss of the normal (system connected) station service transformer will result in a trip of a BES generating Facility?

The SDT does not intend that the system-connected station service transformers be included in the Applicability. The generator-connected station service transformers and generator connected excitation transformers are often connected to the generator bus directly without an interposing breaker; thus, the Protection Systems on these transformers will trip the generator as discussed in 4.2.5.1.

What is meant by "verify operation of the relay inputs and outputs that are essential to proper functioning of the Protection System?"

Any input or output (of the relay) that "affects the tripping" of the breaker is included in the scope of I/O of the relay to be verified. By "affects the tripping," one needs to realize that sometimes there are more inputs and outputs than simply the output to the trip coil. Many important protective functions include things like breaker fail initiation, zone timer initiation and sometimes even 52a/b contact inputs are needed for a protective relay to correctly operate.

Each input should be "picked up" or "turned on and off" and verified as changing state by the microprocessor of the relay. Each output should be "operated" or "closed and opened" from the microprocessor of the relay and the output should be verified to change state on the output terminals of the relay. One possible method of testing inputs of these relays is to "jumper" the needed dc voltage to the input and verify that the relay registered the change of state.

Electromechanical lock-out relays (86) (used to convey the tripping current to the trip coils) need to be electrically operated to prove the capability of the device to change state. These tests need to be accomplished at least every six years, unless PBM methodology is applied.

The contacts on the 86 or auxiliary tripping relays (94) that change state to pass on the trip current to a breaker trip coil need only be checked every 12 years with the control circuitry.

What is the difference between a distributed UFLS/UVLS and a non-distributed UFLS/UVLS scheme?

A distributed UFLS or UVLS scheme contains individual relays which make independent Load shed decisions based on applied settings and localized voltage and/or current inputs. A distributed scheme may involve an enable/disable contact in the scheme and still be considered a distributed scheme. A non-distributed UFLS or UVLS scheme involves a system where there is some type of centralized measurement and Load shed decision being made. A non-distributed UFLS/UVLS scheme is considered similar to an SPS scheme and falls under Table 1 for maintenance activities and intervals.

8.2 Retention of Records

PRC-005-1 describes a reporting or auditing cycle of one year and retention of records for three years. However, with a three-year retention cycle, the records of verification for a Protection System might be discarded before the next verification, leaving no record of what was done if a Misoperation or failure is to be analyzed.

PRC-005-X corrects this by requiring:

The Transmission Owner, Generator Owner, and Distribution Provider shall each retain documentation of the most recent performance of each distinct maintenance activity for the Protection System, Automatic Reclosing, or Sudden Pressure Relaying Component, or to the previous scheduled (on-site) audit date, whichever is longer.

This requirement assures that the documentation shows that the interval between maintenance cycles correctly meets the maintenance interval limits. The requirement is actually alerting the industry to documentation requirements already implemented by audit teams. Evidence of compliance bookending the interval shows interval accomplished instead of proving only your planned interval.

The SDT is aware that, in some cases, the retention period could be relatively long. But, the retention of documents simply helps to demonstrate compliance.

8.2.1 Frequently Asked Questions:

Please clarify the data retention requirements.

The data retention requirements are intended to allow the availability of maintenance records to demonstrate that the time intervals in your maintenance plan were upheld.

Maximum Maintenance Interval	Data Retention Period
4 Months, 6 Months,18 Months, or 3 Years	All activities since previous audit

6 Years	All activities since previous audit(assuming a 6 year audit cycle) or most recent performance(assuming 3 year audit cycle), whichever is longer
12 Year	All activities from the most recent performance

If an entity prefers to utilize Performance-Based Maintenance, then statistical data may well be retained for extended periods to assist with future adjustments in time intervals.

If an equipment item is replaced, then the entity can restart the maintenance-time-interval-clock if desired; however, the replacement of equipment does not remove any documentation requirements that would have been required to verify compliance with time-interval requirements. In other words, do not discard maintenance data that goes to verify your work.

The retention of documentation for new and/or replaced equipment is all about proving that the maintenance intervals had been in compliance. For example, a long-range plan of upgrades might lead an entity to ignore required maintenance; retaining the evidence of prior maintenance that existed before any retirements and upgrades proves compliance with the standard.

What does this Maintenance Standard say about commissioning? Is it necessary to have documentation in your maintenance history of the completion of commission testing?

This standard does not establish requirements for commission testing. Commission testing includes all testing activities necessary to conclude that a Facility has been built in accordance with design. While a thorough commission testing program would include, either directly or indirectly, the verification of all those Protection System attributes addressed by the maintenance activities specified in the Tables of PRC-005-X, verification of the adequacy of initial installation necessitates the performance of testing and inspections that go well beyond these routine maintenance activities. For example, commission testing might set baselines for future tests; perform acceptance tests and/or warranty tests; utilize testing methods that are not generally done routinely like staged-Fault-tests.

However, many of the Protection System attributes which are verified during commission testing are not subject to age related or service related degradation, and need not be re-verified within an ongoing maintenance program. Example – it is not necessary to re-verify correct terminal strip wiring on an ongoing basis.

PRC-005-X assumes that thorough commission testing was performed prior to a Protection System being placed in service. PRC-005-X 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.

It should be noted that commission testing frequently is performed by a different organization than that which is responsible for the ongoing maintenance of the Protection System. Furthermore, the commission testing activities will not necessarily correlate directly with the maintenance activities required by the standard. As such, it is very likely that commission testing records will deviate significantly from maintenance records in both form and content; and,

therefore, it is not necessary to maintain commission testing records within the maintenance program documentation.

Notwithstanding the differences in records, an entity would be wise to retain commissioning records to show a maintenance start date. (See below). An entity that requires that their commissioning tests have, at a minimum, the requirements of PRC-005-X would help that entity prove time interval maximums by setting the initial time clock.

How do you determine the initial due date for maintenance?

The initial due date for maintenance should be based upon when a Protection System was tested. Alternatively, an entity may choose to use the date of completion of the commission testing of the Protection System component and the system was placed into service as the starting point in determining its first maintenance due dates. Whichever method is chosen, for newly installed Protection Systems the components should not be placed into service until minimum maintenance activities have taken place.

It is conceivable that there can be a (substantial) difference in time between the date of testing, as compared to the date placed into service. The use of the "Calendar Year" language can help determine the next due date without too much concern about being non-compliant for missing test dates by a small amount (provided your dates are not already at the end of a year). However, if there is a substantial amount of time difference between testing and in-service dates, then the testing date should be followed because it is the degradation of components that is the concern. While accuracy fluctuations may decrease when components are not energized, there are cases when degradation can take place, even though the device is not energized. Minimizing the time between commissioning tests and in-service dates will help.

If I miss two battery inspections four times out of 100 Protection System components on my transmission system, does that count as 2% or 8% when counting Violation Severity Level (VSL) for R3?

The entity failed to complete its scheduled program on two of its 100 Protection System components, which would equate to 2% for application to the VSL Table for Requirement R3. This VSL is written to compare missed components to total components. In this case two components out of 100 were missed, or 2%.

How do I achieve a "grace period" without being out of compliance?

The objective here is to create a time extension within your own PSMP that still does not violate the maximum time intervals stated in the standard. Remember that the maximum time intervals listed in the Tables cannot be extended.

For the purposes of this example, concentrating on just unmonitored protective relays – Table 1-1 specifies a maximum time interval (between the mandated maintenance activities) of six calendar years. Your plan must ensure that your unmonitored relays are tested at least once every six calendar years. You could, within your PSMP, require that your unmonitored relays be tested every four calendar years, with a maximum allowable time extension of 18 calendar months. This allows an entity to have deadlines set for the auto-generation of work orders, but still has the flexibility in scheduling complex work schedules. This also allows for that 18 calendar months to act as a buffer, in effect a grace period within your PSMP, in the event of unforeseen events. You will note that this example of a maintenance plan interval has a planned time of four years; it also has a built-in time extension allowed within the PSMP, and yet does not exceed the maximum time interval allowed by the standard. So while there are no time extensions allowed beyond the standard, an entity can still have substantial flexibility to maintain their Protection System components.

8.3 Basis for Table 1 Intervals

When developing the original *Protection System Maintenance – A Technical Reference* in 2007, the SPCTF collected all available data from Regional Entities (REs) on time intervals recommended for maintenance and test programs. The recommendations vary widely in categorization of relays, defined maintenance actions, and time intervals, precluding development of intervals by averaging. The SPCTF also reviewed the 2005 Report [2] of the IEEE Power System Relaying Committee Working Group I-17 (Transmission Relay System Performance Comparison). Review of the I-17 report shows data from a small number of utilities, with no company identification or means of investigating the significance of particular results.

To develop a solid current base of practice, the SPCTF surveyed its members regarding their maintenance intervals for electromechanical and microprocessor relays, and asked the members to also provide definitively-known data for other entities. The survey represented 470 GW of peak Load, or 4% of the NERC peak Load. Maintenance interval averages were compiled by weighting reported intervals according to the size (based on peak Load) of the reporting utility. Thus, the averages more accurately represent practices for the large populations of Protection Systems used across the NERC regions.

The results of this survey with weighted averaging indicate maintenance intervals of five years for electromechanical or solid state relays, and seven years for unmonitored microprocessor relays.

A number of utilities have extended maintenance intervals for microprocessor relays beyond seven years, based on favorable experience with the particular products they have installed. To provide a technical basis for such extension, the SPCTF authors developed a recommendation of 10 years using the Markov modeling approach from [1], as summarized in Section 8.4. The results of this modeling depend on the completeness of self-testing or monitoring. Accordingly, this extended interval is allowed by Table 1, only when such relays are monitored as specified in the attributes of monitoring contained in Tables 1-1 through 1-5 and Table 2. Monitoring is capable of reporting Protection System health issues that are likely to affect performance within the 10 year time interval between verifications.

It is important to note that, according to modeling results, Protection System availability barely changes as the maintenance interval is varied below the 10-year mark. Thus, reducing the maintenance interval does not improve Protection System availability. With the assumptions of the model regarding how maintenance is carried out, reducing the maintenance interval actually degrades Protection System availability.

8.4 Basis for Extended Maintenance Intervals for Microprocessor Relays

Table 1 allows maximum verification intervals that are extended based on monitoring level. The industry has experience with self-monitoring microprocessor relays that leads to the Table 1 value for a monitored relay, as explained in Section 8.3. To develop a basis for the maximum interval for monitored relays in their *Protection System Maintenance – A Technical Reference*, the SPCTF used the methodology of Reference [1], which specifically addresses optimum routine maintenance intervals. The Markov modeling approach of [1] is judged to be valid for the design and typical failure modes of microprocessor relays.

The SPCTF authors ran test cases of the Markov model to calculate two key probability measures:

- Relay Unavailability - the probability that the relay is out of service due to failure or maintenance activity while the power system Element to be protected is in service.
- Abnormal Unavailability - the probability that the relay is out of service due to failure or maintenance activity when a Fault occurs, leading to failure to operate for the Fault.

The parameter in the Markov model that defines self-monitoring capability is ST (for self-test). ST = 0 if there is no self-monitoring; ST = 1 for full monitoring. Practical ST values are estimated to range from .75 to .95. The SPCTF simulation runs used constants in the Markov model that were the same as those used in [1] with the following exceptions:

Sn, Normal tripping operations per hour = 21600 (reciprocal of normal Fault clearing time of 10 cycles)

Sb, Backup tripping operations per hour = 4320 (reciprocal of backup Fault clearing time of 50 cycles)

Rc, Protected component repairs per hour = 0.125 (8 hours to restore the power system)

Rt, Relay routine tests per hour = 0.125 (8 hours to test a Protection System)

Rr, Relay repairs per hour = 0.08333 (12 hours to complete a Protection System repair after failure)

Experimental runs of the model showed low sensitivity of optimum maintenance interval to these parameter adjustments.

The resulting curves for relay unavailability and abnormal unavailability versus maintenance interval showed a broad minimum (optimum maintenance interval) in the vicinity of 10 years – the curve is flat, with no significant change in either unavailability value over the range of 9, 10, or 11 years. This was true even for a relay mean time between Failures (MTBF) of 50 years, much lower than MTBF values typically published for these relays. Also, the Markov modeling indicates that both the relay unavailability and abnormal unavailability actually become higher with more frequent testing. This shows that the time spent on these more frequent tests yields no failure discoveries that approach the negative impact of removing the relays from service and running the tests.

The PSMT SDT discussed the practical need for "time-interval extensions" or "grace periods" to allow for scheduling problems that resulted from any number of business contingencies. The time interval discussions also focused on the need to reflect industry norms surrounding Generator outage frequencies. Finally, it was again noted that FERC Order 693 demanded maximum time intervals. "Maximum time intervals" by their very term negates any "time-interval extension" or "grace periods." To recognize the need to follow industry norms on Generator outage frequencies and accommodate a form of time-interval extension, while still following FERC Order 693, the Standard Drafting Team arrived at a six-year interval for the electromechanical relay, instead of the five-year interval arrived at by the SPCTF. The PSMT SDT has followed the FERC directive for a *maximum* time interval and has determined that no extensions will be allowed. Six years has been set for the maximum time interval between manual maintenance activities. This maximum time interval also works well for maintenance cycles that have been in use in generator plants for decades.

For monitored relays, the PSMT SDT notes that the SPCTF called for 10 years as the interval between maintenance activities. This 10-year interval was chosen, even though there was "…no significant change in unavailability value over the range of 9, 10, or 11 years. This was true even for a relay Mean Time between Failures (MTBF) of 50 years…" The Standard Drafting Team again sought to align maintenance activities with known successful practices and outage schedules. The Standard does not allow extensions on any component of the Protection System; thus, the maximum allowed interval for these components has been set to 12 years. Twelve years also fits well into the traditional maintenance cycles of both substations and generator plants.

Also of note is the Table's use of the term "Calendar" in the column for "Maximum Maintenance Interval." The PSMT SDT deemed it necessary to include the term "Calendar" to facilitate annual maintenance planning, scheduling and implementation. This need is the result of known occurrences of system requirements that could cause maintenance schedules to be missed by a few days or weeks. The PSMT SDT chose the term "Calendar" to preclude the need to have schedules be met to the day. An electromechanical protective relay that is maintained in year number one need not be revisited until six years later (year number seven). For example, a relay was maintained April 10, 2008; maintenance would need to be completed no later than December 31, 2014.

Though not a requirement of this standard, to stay in line with many Compliance Enforcement Agencies audit processes an entity should define, within their own PSMP, the entity's use of terms like annual, calendar year, etc. Then, once this is within the PSMP, the entity should abide by their chosen language.

9. Performance-Based Maintenance Process

In lieu of using the Table 1 intervals, a Performance-Based Maintenance process may be used to establish maintenance intervals (*PRC-005 Attachment A Criteria for a Performance-Based Protection System Maintenance Program*). A Performance-Based Maintenance process may justify longer maintenance intervals, or require shorter intervals relative to Table 1. In order to use a Performance-Based Maintenance process, the documented maintenance program must include records of repairs, adjustments, and corrections to covered Protection Systems in order to provide historical justification for intervals, other than those established in Table 1. Furthermore, the asset owner must regularly analyze these records of corrective actions to develop a ranking of causes. Recurrent problems are to be highlighted, and remedial action plans are to be documented to mitigate or eliminate recurrent problems.

Entities with Performance-Based Maintenance track performance of Protection Systems, demonstrate how they analyze findings of performance failures and aberrations, and implement continuous improvement actions. Since no maintenance program can ever guarantee that no malfunction can possibly occur, documentation of a Performance-Based Maintenance program would serve the utility well in explaining to regulators and the public a Misoperation leading to a major System outage event.

A Performance-Based Maintenance program requires auditing processes like those included in widely used industrial quality systems (such as ***ISO 9001-2000, Quality Management Systems — Requirements;*** or applicable parts of the NIST Baldridge National Quality Program). The audits periodically evaluate:

- The completeness of the documented maintenance process
- Organizational knowledge of and adherence to the process
- Performance metrics and documentation of results
- Remediation of issues
- Demonstration of continuous improvement.

In order to opt into a Performance-Based Maintenance (PBM) program, the asset owner must first sort the various Components into population segments. Any population segment must be comprised of at least 60 individual units; if any asset owner opts for PBM, but does not own 60 units to comprise a population, then that asset owner may combine data from other asset owners until the needed 60 units is aggregated. Each population segment must be composed of a grouping of Components of a consistent design standard or particular model or type from a single manufacturer and subjected to similar environmental factors. For example: One segment cannot be comprised of both GE & Westinghouse electro-mechanical lock-out relays; likewise, one segment cannot be comprised of 60 GE lock-out relays, 30 of which are in a dirty environment, and the remaining 30 from a clean environment. This PBM process cannot be applied to batteries, but can be applied to all other Components, including (but not limited to) specific battery chargers, instrument transformers, trip coils and/or control circuitry (etc.).

9.1 Minimum Sample Size

Large Sample Size

An assumption that needs to be made when choosing a sample size is "the sampling distribution of the sample mean can be approximated by a normal probability distribution." The Central Limit Theorem states: "In selecting simple random samples of size *n* from a population, the sampling distribution of the sample mean *x* can be approximated by a normal probability distribution as the sample size becomes large." (Essentials of Statistics for Business and Economics, Anderson, Sweeney, Williams, 2003.)

To use the Central Limit Theorem in statistics, the population size should be large. The references below are supplied to help define what is large.

> "… whenever we are using a large simple random sample (rule of thumb: n>=30), the central limit theorem enables us to conclude that the sampling distribution of the sample mean can be approximated by a normal distribution." (Essentials of Statistics for Business and Economics, Anderson, Sweeney, Williams, 2003.)
>
> "If samples of size n, when n>=30, are drawn from any population with a mean *u* and a standard deviation σ, the sampling distribution of sample means approximates a normal distribution. The greater the sample size, the better the approximation." (Elementary Statistics - Picturing the World, Larson, Farber, 2003.)
>
> "The sample size is large (generally n>=30)… (Introduction to Statistics and Data Analysis - Second Edition, Peck, Olson, Devore, 2005.)
>
> "… the normal is often used as an approximation to the *t* distribution in a test of a null hypothesis about the mean of a normally distributed population when the population variance is estimated from a relatively large sample. A sample size exceeding 30 is often given as a minimal size in this connection." (Statistical Analysis for Business Decisions, Peters, Summers, 1968.)

Error of Distribution Formula

Beyond the large sample size discussion above, a sample size requirement can be estimated using the bound on the Error of Distribution Formula when the expected result is of a "Pass/Fail" format and will be between 0 and 1.0.

The Error of Distribution Formula is:

$$B = z\sqrt{\frac{\pi(1-\pi)}{n}}$$

Where:

B = bound on the error of distribution (allowable error)

z = standard error

π = expected failure rate

n = sample size required

Solving for n provides:

$$n = \pi(1 - \pi)\left(\frac{z}{B}\right)^2$$

Minimum Population Size to use Performance-Based Program

One entity's population of components should be large enough to represent a sizeable sample of a vendor's overall population of manufactured devices. For this reason, the following assumptions are made:

B = 5%

z = 1.96 (This equates to a 95% confidence level)

π = 4%

Using the equation above, n=59.0.

Minimum Sample Size to evaluate Performance-Based Program

The number of components that should be included in a sample size for evaluation of the appropriate testing interval can be smaller because a lower confidence level is acceptable since the sample testing is repeated or updated annually. For this reason, the following assumptions are made:

B = 5%

z = 1.44 (85% confidence level)

π = 4%

Using the equation above, n=31.8.

Recommendation

Based on the above discussion, a sample size should be at least 30 to allow use of the equation mentioned. Using this and the results of the equation, the following numbers are recommended (and required within the standard):

Minimum Population Size to use Performance-Based Maintenance Program = 60

Minimum Sample Size to evaluate Performance-Based Program = 30.

Once the population segment is defined, then maintenance must begin within the intervals as outlined for the device described in the Tables 1-1 through 1-5. Time intervals can be lengthened provided the last year's worth of components tested (or the last 30 units maintained, whichever is more) had fewer than 4% Countable Events. It is notable that 4% is specifically chosen because an entity with a small population (30 units) would have to adjust its time intervals between maintenance if more than one Countable Event was found to have occurred during the last analysis period. A smaller percentage would require that entity to adjust the time interval between maintenance activities if even one unit is found out of tolerance or causes a Misoperation.

The minimum number of units that can be tested in any given year is 5% of the population. Note that this 5% threshold sets a practical limitation on total length of time between intervals at 20 years.

If at any time the number of Countable Events equals or exceeds 4% of the last year's tested components (or the last 30 units maintained, whichever is more), then the time period between manual maintenance activities must be decreased. There is a time limit on reaching the decreased time at which the Countable Events is less than 4%; this must be attained within three years.

Performance-Based Program Evaluation Example

The 4% performance target was derived as a protection system performance target and was selected based on the drafting team's experience and studies performed by several utilities. This is not derived from the performance of discrete devices. Microprocessor relays and electromechanical relays have different performance levels. It is not appropriate to compare these performance levels to each other. The performance of the segment should be compared to the 4% performance criteria.

In consideration of the use of Performance Based Maintenance (PBM), the user should consider the effects of extended testing intervals and the established 4% failure rate. In the table shown below, the segment is 1000 units. As the testing interval (in years) increases, the number of units tested each year decreases. The number of countable events allowed is 4% of the tested units. Countable events are the failure of a Component requiring repair or replacement, any corrective actions performed during the maintenance test on the units within the testing segment (units per year), or any misoperation attributable to hardware failure or calibration failure found within the entire segment (1000 units) during the testing year.

Example: 1000 units in the segment with a testing interval of 8 years: The number of units tested each year will be 125 units. The total allowable countable events equals: 125 X .04 = 5. This number includes failure of a Component requiring repair or replacement, corrective issues found during testing, and the total number of misoperations (attributable to hardware or calibration failure within the testing year) associated with the entire segment of 1000 units.

Example: 1000 units in the segment with a testing interval of 16 years: The number of units tested each year will be 63 units. The total allowable countable events equals: 63 X .04 = 2.5.

As shown in the above examples, doubling the testing interval reduces the number of allowable events by half.

Total number of units in the segment	1000
Failure rate	4.00%

Testing Intervals (Years)	Units Per Year	Acceptable Number of Countable Events per year	Yearly Failure Rate Based on 1000 Units in Segment
1	1000.00	40.00	4.00%
2	500.00	20.00	2.00%
4	250.00	10.00	1.00%
6	166.67	6.67	0.67%
8	125.00	5.00	0.50%
10	100.00	4.00	0.40%
12	83.33	3.33	0.33%
14	71.43	2.86	0.29%
16	62.50	2.50	0.25%
18	55.56	2.22	0.22%
20	50.00	2.00	0.20%

Using the prior year's data, determine the maximum allowable maintenance interval for each Segment such that the Segment experiences Countable Events on no more than 4% of the Components within the Segment, for the greater of either the last 30 Components maintained or all Components maintained in the previous year.

Segment – Components of a consistent design standard, or a particular model or type from a single manufacturer that typically share other common elements. Consistent performance is expected across the entire population of a Segment. A Segment must contain at least sixty (60) individual Components.

Countable Event – A failure of a Component requiring repair or replacement, any condition discovered during the maintenance activities in Tables 1-1 through 1-5, Table 3, Table 4-1 through Table 4-2, and Table 5, which requires corrective action or a Protection System Misoperation attributed to hardware failure or calibration failure. Misoperations due to product design errors, software errors, relay settings different from specified settings, Protection System Component, Automatic Reclosing, or Sudden Pressure Relaying configuration or application errors are not included in Countable Events.

9.2 Frequently Asked Questions:

I'm a small entity and cannot aggregate a population of Protection System components to establish a segment required for a Performance-Based Protection System Maintenance Program. How can I utilize that opportunity?

Multiple asset owning entities may aggregate their individually owned populations of individual Protection System components to create a segment that crosses ownership boundaries. All entities participating in a joint program should have a single documented joint management

process, with consistent Protection System Maintenance Programs (practices, maintenance intervals and criteria), for which the multiple owners are individually responsible with respect to the requirements of the Standard. The requirements established for Performance-Based Maintenance must be met for the overall aggregated program on an ongoing basis.

The aggregated population should reflect all factors that affect consistent performance across the population, including any relevant environmental factors such as geography, power-plant vs. substation, and weather conditions.

Can an owner go straight to a Performance-Based Maintenance program schedule, if they have previously gathered records?

Yes. An owner can go to a Performance-Based Maintenance program immediately. The owner will need to comply with the requirements of a Performance-Based Maintenance program as listed in the Standard. Gaps in the data collected will not be allowed; therefore, if an owner finds that a gap exists such that they cannot prove that they have collected the data as required for a Performance-Based Maintenance program then they will need to wait until they can prove compliance.

When establishing a Performance-Based Maintenance program, can I use test data from the device manufacturer, or industry survey results, as results to help establish a basis for my Performance-Based intervals?

No, you must use actual in-service test data for the components in the segment.

What types of Misoperations or events are not considered Countable Events in the Performance-Based Protection System Maintenance (PBM) Program?

Countable Events are intended to address conditions that are attributed to hardware failure or calibration failure; that is, conditions that reflect deteriorating performance of the component. These conditions include any condition where the device previously worked properly, then, due to changes within the device, malfunctioned or degraded to the point that re-calibration (to within the entity's tolerance) was required.

For this purpose of tracking hardware issues, human errors resulting in Protection System Misoperations during system installation or maintenance activities are not considered Countable Events. Examples of excluded human errors include relay setting errors, design errors, wiring errors, inadvertent tripping of devices during testing or installation, and misapplication of Protection System components. Examples of misapplication of Protection System components include wrong CT or PT tap position, protective relay function misapplication, and components not specified correctly for their installation. Obviously, if one is setting up relevant data about hardware failures then human failures should be eliminated from the hardware performance analysis.

One example of human-error is not pertinent data might be in the area of testing "86" lock-out relays (LOR). "Entity A" has two types of LOR's type "X" and type "Y"; they want to move into a performance based maintenance interval. They have 1000 of each type, so the population variables are met. During electrical trip testing of all of their various schemes over the initial six-year interval they find zero type "X" failures, but human error led to tripping a BES Element 100 times; they find 100 type "Y" failures and had an additional 100 human-error caused tripping incidents. In this example the human-error caused Misoperations should not be used to judge the performance of either type of LOR. Analysis of the data might lead "Entity A" to change time intervals. Type "X" LOR can be placed into extended time interval testing because of its low failure

rate (zero failures) while Type "Y" would have to be tested more often than every 6 calendar years (100 failures divided by 1000 units exceeds the 4% tolerance level).

Certain types of Protection System component errors that cause Misoperations are not considered Countable Events. Examples of excluded component errors include device malfunctions that are correctable by firmware upgrades and design errors that do not impact protection function.

What are some examples of methods of correcting segment perfomance for Performance-Based Maintenance?

There are a number of methods that may be useful for correcting segment performance for mal-performing segments in a Performance-Based Maintenance system. Some examples are listed below.

- The maximum allowable interval, as established by the Performance-Based Maintenance system, can be decreased. This may, however, be slow to correct the performance of the segment.
- Identifiable sub-groups of components within the established segment, which have been identified to be the mal-performing portion of the segment, can be broken out as an independent segment for target action. Each resulting segment must satisfy the minimum population requirements for a Performance-Based Maintenance program in order to remain within the program.
- Targeted corrective actions can be taken to correct frequently occurring problems. An example would be replacement of capacitors within electromechanical distance relays if bad capacitors were determined to be the cause of the mal-performance.
- components within the mal-performing segment can be replaced with other components (electromechanical distance relays with microprocessor relays, for example) to remove the mal-performing segment.

If I find (and correct) a Unresolved Maintenance Issue as a result of a Misoperation investigation (Re: PRC-004), how does this affect my Performance-Based Maintenance program?

If you perform maintenance on a Protection System component for any reason (including as part of a PRC-004 required Misoperation investigation/corrective action), the actions performed can count as a maintenance activity provided the activities in the relevant Tables have been done, and, if you desire, "reset the clock" on everything you've done. In a Performance-Based Maintenance program, you also need to record the Unresolved Maintenance Issue as a Countable Event within the relevant component group segment and use it in the analysis to determine your correct Performance-Based Maintenance interval for that component group. Note that "resetting the clock" should not be construed as interfering with an entity's routine testing schedule because the "clock-reset" would actually make for a decreased time interval by the time the next routine test schedule comes around.

For example a relay scheme, consisting of four relays, is tested on 1-1-11 and the PSMP has a time interval of 3 calendar years with an allowable extension of 1 calendar year. The relay would be due again for routine testing before the end of the year 2015. This mythical relay scheme has a Misoperation on 6-1-12 that points to one of the four relays as bad. Investigation proves a bad

relay and a new one is tested and installed in place of the original. This replacement relay actually could be retested before the end of the year 2016 (clock-reset) and not be out of compliance. This requires tracking maintenance by individual relays and is allowed. However, many companies schedule maintenance in other ways like by substation or by circuit breaker or by relay scheme. By these methods of tracking maintenance that “replaced relay” will be retested before the end of the year 2015. This is also acceptable. In no case was a particular relay tested beyond the PSMP of four years max, nor was the 6 year max of the Standard exceeded. The entity can reset the clock if they desire or the entity can continue with original schedules and, in effect, test even more frequently.

Why are batteries excluded from PBM? What about exclusion of batteries from condition based maintenance?

Batteries are the only element of a Protection System that is a perishable item with a shelf life. As a perishable item batteries require not only a constant float charge to maintain their freshness (charge), but periodic inspection to determine if there are problems associated with their aging process and testing to see if they are maintaining a charge or can still deliver their rated output as required.

Besides being perishable, a second unique feature of a battery that is unlike any other Protection System element is that a battery uses chemicals, metal alloys, plastics, welds, and bonds that must interact with each other to produce the constant dc source required for Protection Systems, undisturbed by ac system Disturbances.

No type of battery manufactured today for Protection System application is free from problems that can only be detected over time by inspection and test. These problems can arise from variances in the manufacturing process, chemicals and alloys used in the construction of the individual cells, quality of welds and bonds to connect the components, the plastics used to make batteries and the cell forming process for the individual battery cells.

Other problems that require periodic inspection and testing can result from transportation from the factory to the job site, length of time before a charge is put on the battery, the method of installation, the voltage level and duration of equalize charges, the float voltage level used, and the environment that the battery is installed in.

All of the above mentioned factors and several more not discussed here are beyond the control of the Functional Entities that want to use a Performance-Based Protection System Maintenance (PBM) program. These inherent variances in the aging process of a battery cell make establishment of a designated segment based on manufacturer and type of battery impossible.

The whole point of PBM is that if all variables are isolated then common aging and performance criteria would be the same. However, there are too many variables in the electrochemical process to completely isolate all of the performance-changing criteria.

Similarly, Functional Entities that want to establish a condition-based maintenance program using the highest levels of monitoring, resulting in the least amount of hands-on maintenance activity, cannot completely eliminate some periodic maintenance of the battery used in a station dc supply. Inspection of the battery is required on a Maximum Maintenance Interval listed in the tables due to the aging processes of station batteries. However, higher degrees of

monitoring of a battery can eliminate the requirement for some periodic testing and some inspections (see Table 1-4).

Please provide an example of the calculations involved in extending maintenance time intervals using PBM.

Entity has 1000 GE-HEA lock-out relays; this is greater than the minimum sample requirement of 60. They start out testing all of the relays within the prescribed Table requirements (6 year max) by testing the relays every 5 years. The entity's plan is to test 200 units per year; this is greater than the minimum sample size requirement of 30. For the sake of example only the following will show 6 failures per year, reality may well have different numbers of failures every year. PBM requires annual assessment of failures found per units tested. After the first year of tests the entity finds 6 failures in the 200 units tested. 6/200= 3% failure rate. This entity is now allowed to extend the maintenance interval if they choose. The entity chooses to extend the maintenance interval of this population segment out to 10 years. This represents a rate of 100 units tested per year; entity selects 100 units to be tested in the following year. After that year of testing these 100 units the entity again finds 6 failed units. 6/100= 6% failures. This entity has now exceeded the acceptable failure rate for these devices and must accelerate testing of all of the units at a higher rate such that the failure rate is found to be less than 4% per year; the entity has three years to get this failure rate down to 4% or less (per year). In response to the 6% failure rate, the entity decreases the testing interval to 8 years. This means that they will now test 125 units per year (1000/8). The entity has just two years left to get the test rate corrected.

After a year, they again find six failures out of the 125 units tested. 6/125= 5% failures. In response to the 5% failure rate, the entity decreases the testing interval to seven years. This means that they will now test 143 units per year (1000/7). The entity has just one year left to get the test rate corrected. After a year, they again find six failures out of the 143 units tested. 6/143= 4.2% failures.

(Note that the entity has tried five years and they were under the 4% limit and they tried seven years and they were over the 4% limit. They must be back at 4% failures or less in the next year so they might simply elect to go back to five years.)

Instead, in response to the 5% failure rate, the entity decreases the testing interval to six years. This means that they will now test 167 units per year (1000/6). After a year, they again find six failures out of the 167 units tested. 6/167= 3.6% failures. Entity found that they could maintain the failure rate at no more than 4% failures by maintaining the testing interval at six years or less. Entity chose six-year interval and effectively extended their TBM (five years) program by 20%.

A note of practicality is that an entity will probably be in better shape to lengthen the intervals between tests if the failure rate is less than 2%. But the requirements allow for annual adjustments, if the entity desires. As a matter of maintenance management, an ever-changing test rate (units tested/year) may be un-workable.

Note that the "5% of components" requirement effectively sets a practical limit of 20 year maximum PBM interval. Also of note is the "3 years" requirement; an entity might arbitrarily extend time intervals from six years to 20 years. In the event that an entity finds a failure rate greater than 4%, then the test rate must be accelerated such that within three years the failure rate must be brought back down to 4% or less.

Here is a table that demonstrates the values discussed:

Year #	Total Population (P)	Test Interval (I)	Units to be Tested (U= P/I)	# of Failures Found (F)	Failure Rate (=F/U)	Decision to Change Interval Yes or No	Interval Chosen
1	1000	5 yrs	200	6	3%	Yes	10 yrs
2	1000	10 yrs	100	6	6%	Yes	8 yrs
3	1000	8 yrs	125	6	5%	Yes	7 yrs
4	1000	7 yrs	143	6	4.2%	Yes	6 yrs
5	1000	6 yrs	167	6	3.6%	No	6 yrs

Please provide an example of the calculations involved in extending maintenance time intervals using PBM for control circuitry.

Note that the following example captures "Control Circuitry" as all of the trip paths associated with a particular trip coil of a circuit breaker. An entity is not restricted to this method of counting control circuits. Perhaps another method an entity would prefer would be to simply track every individual (parallel) trip path. Or perhaps another method would be to track all of the trip outputs from a specific (set) of relays protecting a specific element. Under the included definition of "component":

The designation of what constitutes a control circuit component is very dependent upon how an entity performs and tracks the testing of the control circuitry. Some entities test their control circuits on a breaker basis whereas others test their circuitry on a local zone of protection basis. Thus, entities are allowed the latitude to designate their own definitions of control circuit components. Another example of where the entity has some discretion on determining what constitutes a single component is the voltage and current sensing devices, where the entity may choose either to designate a full three-phase set of such devices or a single device as a single component.

And in Attachment A (PBM) the definition of Segment:

Segment *–Components of a consistent design standard, or a particular model or type from a single manufacturer that typically share other common elements. Consistent performance is expected across the entire population of a segment. A segment must contain at least sixty (60) individual components.*

Example:

Entity has 1,000 circuit breakers, all of which have two trip coils, for a total of 2,000 trip coils; if all circuitry was designed and built with a consistent (internal entity) standard, then this is greater than the minimum sample requirement of 60.

For the sake of further example, the following facts are given:

Half of all relay panels (500) were built 40 years ago by an outside contractor, consisted of asbestos wrapped 600V-insulation panel wiring, and the cables exiting the control house are THHN pulled in conduit direct to exactly half of all of the various circuit breakers. All of the relay panels and cable pulls were built with consistent standards and consistent performance standard expectations within the segment (which is greater than 60). Each relay panel has redundant microprocessor (MPC) relays (retrofitted); each MPC relay supplies an individual trip output to each of the two trip coils of the assigned circuit breaker.

Approximately 35 years ago, the entity developed their own internal construction crew and now builds all of their own relay panels from parts supplied from vendors that meet the entity's specifications, including SIS 600V insulation wiring and copper-sheathed cabling within the direct conduits to circuit breakers. The construction crew uses consistent standards in the construction. This newer segment of their control circuitry population is different than the original segment, consistent (standards, construction and performance expectations) within the new segment and constitutes the remainder of the entity's population (another 500 panels and the cabling to the remaining 500 circuit breakers). Each relay panel has redundant microprocessor (MPC) relays; each MPC relay supplies an individual trip output to each of the two trip coils of the assigned circuit breaker. Every trip path in this newer segment has a device that monitors the voltage directly across the trip contacts of the MPC relays and alarms via RTU and SCADA to the operations control room. This monitoring device, when not in alarm, demonstrates continuity all the way through the trip coil, cabling and wiring back to the trip contacts of the MPC relay.

The entity is tracking 2,000 trip coils (each consisting of multiple trip paths) in each of these two segments. But half of all of the trip paths are monitored; therefore, the trip paths are continuously tested and the circuit will alarm when there is a failure. These alarms have to be verified every 12 years for correct operation.

The entity now has 1,000 trip coils (and associated trip paths) remaining that they have elected to count as control circuits. The entity has instituted a process that requires the verification of every trip path to each trip coil (one unit), including the electrical activation of the trip coil. (The entity notes that the trip coils will have to be tripped electrically more often than the trip path verification, and is taking care of this activity through other documentation of Real-time Fault operations.)

They start out testing all of the trip coil circuits within the prescribed Table requirements (12-year max) by testing the trip circuits every 10 years. The entity's plan is to test 100 units per year; this is greater than the minimum sample size requirement of 30. For the sake of example only, the following will show three failures per year; reality may well have different numbers of failures every year. PBM requires annual assessment of failures found per units tested. After the first year of tests, the entity finds three failures in the 100 units tested. 3/100= 3% failure rate.

This entity is now allowed to extend the maintenance interval, if they choose. The entity chooses to extend the maintenance interval of this population segment out to 20 years. This represents a rate of 50 units tested per year; entity selects 50 units to be tested in the following year. After that year of testing these 50 units, the entity again finds three failed units. 3/50= 6% failures.

This entity has now exceeded the acceptable failure rate for these devices and must accelerate testing of all of the units at a higher rate, such that the failure rate is found to be less than 4% per year; the entity has three years to get this failure rate down to 4% or less (per year).

In response to the 6% failure rate, the entity decreases the testing interval to 16 years. This means that they will now test 63 units per year (1000/16). The entity has just two years left to get the test rate corrected. After a year, they again find three failures out of the 63 units tested. 3/63= 4.76% failures.

In response to the >4% failure rate, the entity decreases the testing interval to 14 years. This means that they will now test 72 units per year (1000/14). The entity has just one year left to get the test rate corrected. After a year, they again find three failures out of the 72 units tested. 3/72= 4.2% failures.

(Note that the entity has tried 10 years, and they were under the 4% limit; and they tried 14 years, and they were over the 4% limit. They must be back at 4% failures or less in the next year, so they might simply elect to go back to 10 years.)

Instead, in response to the 4.2% failure rate, the entity decreases the testing interval to 12 years. This means that they will now test 84 units per year (1000/12). After a year, they again find three failures out of the 84 units tested. 3/84= 3.6% failures.

Entity found that they could maintain the failure rate at no more than 4% failures by maintaining the testing interval at 12 years or less. Entity chose 12-year interval, and effectively extended their TBM (10 years) program by 20%.

A note of practicality is that an entity will probably be in better shape to lengthen the intervals between tests if the failure rate is less than 2%. But the requirements allow for annual adjustments if the entity desires. As a matter of maintenance management, an ever-changing test rate (units tested / year) may be un-workable.

Note that the "5% of components" requirement effectively sets a practical limit of 20-year maximum PBM interval. Also of note is the "3 years" requirement; an entity might arbitrarily extend time intervals from six years to 20 years. In the event that an entity finds a failure rate greater than 4%, then the test rate must be accelerated such that within three years the failure rate must be brought back down to 4% or less.

Here is a table that demonstrates the values discussed:

Year #	Total Population (P)	Test Interval (I)	Units to be Tested (U= P/I)	# of Failures Found (F)	Failure Rate (=F/U)	Decision to Change Interval Yes or No	Interval Chosen
1	1000	10 yrs	100	3	3%	Yes	20 yrs
2	1000	20 yrs	50	3	6%	Yes	16yrs
3	1000	16 yrs	63	3	4.8%	Yes	14 yrs
4	1000	14 yrs	72	3	4.2%	Yes	12 yrs
5	1000	12 yrs	84	3	3.6%	No	12 yrs

Please provide an example of the calculations involved in extending maintenance time intervals using PBM for voltage and current sensing devices.

Note that the following example captures "voltage and current inputs to the protective relays" as all of the various current transformer and potential transformer signals associated with a particular set of relays used for protection of a specific Element. This entity calls this set of protective relays a "Relay Scheme." Thus, this entity chooses to count PT and CT signals as a group instead of individually tracking maintenance activities to specific bushing CT's or specific PT's. An entity is not restricted to this method of counting voltage and current devices, signals and paths. Perhaps another method an entity would prefer would be to simply track every individual PT and CT. Note that a generation maintenance group may well select the latter because they may elect to perform routine off-line tests during generator outages, whereas a transmission maintenance group might create a process that utilizes Real-time system values measured at the relays. Under the included definition of "component":

The designation of what constitutes a control circuit component is very dependent upon how an entity performs and tracks the testing of the control circuitry. Some entities test their control circuits on a breaker basis whereas others test their circuitry on a local zone of protection basis. Thus, entities are allowed the latitude to designate their own definitions of control circuit components. Another example of where the entity has some discretion on determining what constitutes a single component is the voltage and current sensing devices, where the entity may choose either to designate a full three-phase set of such devices or a single device as a single component.

And in Attachment A (PBM) the definition of Segment:

Segment –*Components of a consistent design standard, or a particular model or type from a single manufacturer that typically share other common elements. Consistent performance is expected across the entire population of a segment. A segment must contain at least sixty (60) individual components.*

Example:

Entity has 2000 "Relay Schemes," all of which have three current signals supplied from bushing CTs, and three voltage signals supplied from substation bus PT's. All cabling and circuitry was designed and built with a consistent (internal entity) standard, and this population is greater than the minimum sample requirement of 60.

For the sake of further example the following facts are given:

Half of all relay schemes (1,000) are supplied with current signals from ANSI STD C800 bushing CTs and voltage signals from PTs built by ACME Electric MFR CO. All of the relay panels and cable pulls were built with consistent standards, and consistent performance standard expectations exist for the consistent wiring, cabling and instrument transformers within the segment (which is greater than 60).

The other half of the entity's relay schemes have MPC relays with additional monitoring built-in that compare DNP values of voltages and currents (or Watts and VARs), as interpreted by the MPC relays and alarm for an entity-accepted tolerance level of accuracy. This newer segment of their "Voltage and Current Sensing" population is different than the original segment, consistent (standards, construction and performance expectations) within the new segment and constitutes the remainder of the entity's population.

The entity is tracking many thousands of voltage and current signals within 2,000 relay schemes (each consisting of multiple voltage and current signals) in each of these two segments. But half of all of the relay schemes voltage and current signals are monitored; therefore, the voltage and current signals are continuously tested and the circuit will alarm when there is a failure; these alarms have to be verified every 12 years for correct operation.

The entity now has 1,000 relay schemes worth of voltage and current signals remaining that they have elected to count within their relay schemes designation. The entity has instituted a process that requires the verification of these voltage and current signals within each relay scheme (one unit).

(Please note - a problem discovered with a current or voltage signal found at the relay could be caused by anything from the relay, all the way to the signal source itself. Having many sources of problems can easily increase failure rates beyond the rate of failures of just one item (for example just PTs). It is the intent of the SDT to minimize failure rates of all of the equipment to an acceptable level; thus, any failure of any item that gets the signal from source to relay is counted. It is for this reason that the SDT chose to set the boundary at the ability of the signal to be delivered all the way to the relay.

The entity will start out measuring all of the relay scheme voltage and currents at the individual relays within the prescribed Table requirements (12 year max) by measuring the voltage and current values every 10 years. The entity's plan is to test 100 units per year; this is greater than the minimum sample size requirement of 30. For the sake of example only, the following will show three failures per year; reality may well have different numbers of failures every year. PBM requires annual assessment of failures found per units tested. After the first year of tests, the entity finds three failures in the 100 units tested. 3/100= 3% failure rate.

This entity is now allowed to extend the maintenance interval, if they choose. The entity chooses to extend the maintenance interval of this population segment out to 20 years. This represents a rate of 50 units tested per year; entity selects 50 units to be tested in the following year. After that year of testing these 50 units, the entity again finds three failed units. 3/50= 6% failures.

This entity has now exceeded the acceptable failure rate for these devices and must accelerate testing of all of the units at a higher rate, such that the failure rate is found to be less than 4% per year; the entity has three years to get this failure rate down to 4% or less (per year).

In response to the 6% failure rate, the entity decreases the testing interval to 16 years. This means that they will now test 63 units per year (1000/16). The entity has just two years left to get the test rate corrected. After a year, they again find three failures out of the 63 units tested. 3/63= 4.76% failures.

In response to the >4%failure rate, the entity decreases the testing interval to 14 years. This means that they will now test 72 units per year (1000/14). The entity has just one year left to get the test rate corrected. After a year, they again find three failures out of the 72 units tested. 3/72= 4.2% failures.

(Note that the entity has tried 10 years, and they were under the 4% limit; and they tried 14 years, and they were over the 4% limit. They must be back at 4% failures or less in the next year, so they might simply elect to go back to 10 years.)

Instead, in response to the 4.2% failure rate, the entity decreases the testing interval to 12 years. This means that they will now test 84 units per year (1,000/12). After a year, they again find three failures out of the 84 units tested. 3/84= 3.6% failures.

Entity found that they could maintain the failure rate at no more than 4% failures by maintaining the testing interval at 12 years or less. Entity chose 12-year interval and effectively extended their TBM (10 years) program by 20%.

A note of practicality is that an entity will probably be in better shape to lengthen the intervals between tests if the failure rate is less than 2%. But the requirements allow for annual adjustments, if the entity desires. As a matter of maintenance management, an ever-changing test rate (units tested/year) may be un-workable.

Note that the "5% of components" requirement effectively sets a practical limit of 20-year maximum PBM interval. Also of note is the "3 years" requirement; an entity might arbitrarily extend time intervals from six years to 20 years. In the event that an entity finds a failure rate greater than 4%, then the test rate must be accelerated such that within three years the failure rate must be brought back down to 4% or less.

Here is a table that demonstrates the values discussed:

Year #	Total Population (P)	Test Interval (I)	Units to be Tested (U= P/I)	# of Failures Found (F)	Failure Rate (=F/U)	Decision to Change Interval Yes or No	Interval Chose
1	1000	10 yrs	100	3	3%	Yes	20 yrs
2	1000	20 yrs	50	3	6%	Yes	16yrs
3	1000	16 yrs	63	3	4.8%	Yes	14 yrs
4	1000	14 yrs	72	3	4.2%	Yes	12 yrs
5	1000	12 yrs	84	3	3.6%	No	12 yrs

10. Overlapping the Verification of Sections of the Protection System

Tables 1-1 through 1-5 require that every Protection System component be periodically verified. One approach, but not the only method, is to test the entire protection scheme as a unit, from the secondary windings of voltage and current sources to breaker tripping. For practical ongoing verification, sections of the Protection System may be tested or monitored individually. The boundaries of the verified sections must overlap to ensure that there are no gaps in the verification. See Appendix A of this Supplementary Reference for additional discussion on this topic.

All of the methodologies expressed within this report may be combined by an entity, as appropriate, to establish and operate a maintenance program. For example, a Protection System may be divided into multiple overlapping sections with a different maintenance methodology for each section:

- Time-based maintenance with appropriate maximum verification intervals for categories of equipment, as given in the Tables 1-1 through 1-5;
- Monitoring as described in Tables 1-1 through 1-5;
- A Performance-Based Maintenance program as described in Section 9 above, or Attachment A of the standard;
- Opportunistic verification using analysis of Fault records, as described in Section 11

10.1 Frequently Asked Questions:

My system has alarms that are gathered once daily through an auto-polling system; this is not really a conventional SCADA system but does it meet the Table 1 requirements for inclusion as a monitored system?

Yes, provided the auto-polling that gathers the alarms reports those alarms to a location where the action can be initiated to correct the Unresolved Maintenance Issue. This location does not have to be the location of the engineer or the technician that will eventually repair the problem, but rather a location where the action can be initiated.

11. Monitoring by Analysis of Fault Records

Many users of microprocessor relays retrieve Fault event records and oscillographic records by data communications after a Fault. They analyze the data closely if there has been an apparent Misoperation, as NERC standards require. Some advanced users have commissioned automatic Fault record processing systems that gather and archive the data. They search for evidence of component failures or setting problems hidden behind an operation whose overall outcome seems to be correct. The relay data may be augmented with independently captured Digital Fault Recorder (DFR) data retrieved for the same event.

Fault data analysis comprises a legitimate CBM program that is capable of reducing the need for a manual time-interval based check on Protection Systems whose operations are analyzed. Even electromechanical Protection Systems instrumented with DFR channels may achieve some CBM benefit. The completeness of the verification then depends on the number and variety of Faults in the vicinity of the relay that produce relay response records and the specific data captured.

A typical Fault record will verify particular parts of certain Protection Systems in the vicinity of the Fault. For a given Protection System installation, it may or may not be possible to gather within a reasonable amount of time an ensemble of internal and external Fault records that completely verify the Protection System.

For example, Fault records may verify that the particular relays that tripped are able to trip via the control circuit path that was specifically used to clear that Fault. A relay or DFR record may indicate correct operation of the protection communications channel. Furthermore, other nearby Protection Systems may verify that they restrain from tripping for a Fault just outside their respective zones of protection. The ensemble of internal Fault and nearby external Fault event data can verify major portions of the Protection System, and reset the time clock for the Table 1 testing intervals for the verified components only.

What can be shown from the records of one operation is very specific and limited. In a panel with multiple relays, only the specific relay(s) whose operation can be observed without ambiguity should be used. Be careful about using Fault response data to verify that settings or calibration are correct. Unless records have been captured for multiple Faults close to either side of a setting boundary, setting or calibration could still be incorrect.

PMU data, much like DME data, can be utilized to prove various components of the Protection System. Obviously, care must be taken to attribute proof only to the parts of a Protection System that can actually be proven using the PMU or DME data.

If Fault record data is used to show that portions or all of a Protection System have been verified to meet Table 1 requirements, the owner must retain the Fault records used, and the maintenance-related conclusions drawn from this data and used to defer Table 1 tests, for at least the retention time interval given in Section 8.2.

11.1 Frequently Asked Questions:

I use my protective relays for Fault and Disturbance recording, collecting oscillographic records and event records via communications for Fault analysis to meet NERC and DME requirements. What are the maintenance requirements for the relays?

For relays used only as Disturbance Monitoring Equipment, NERC Standard PRC-018-1 R3 & R6 states the maintenance requirements and is being addressed by a standards activity that is revising PRC-002-1 and PRC-018-1. For protective relays "that are designed to provide protection for the BES," this standard applies, even if they also perform DME functions.

12. Importance of Relay Settings in Maintenance Programs

In manual testing programs, many utilities depend on pickup value or zone boundary tests to show that the relays have correct settings and calibration. Microprocessor relays, by contrast, provide the means for continuously monitoring measurement accuracy. Furthermore, the relay digitizes inputs from one set of signals to perform all measurement functions in a single self-monitoring microprocessor system. These relays do not require testing or calibration of each setting.

However, incorrect settings may be a bigger risk with microprocessor relays than with older relays. Some microprocessor relays have hundreds or thousands of settings, many of which are critical to Protection System performance.

Monitoring does not check measuring element settings. Analysis of Fault records may or may not reveal setting problems. To minimize risk of setting errors after commissioning, the user should enforce strict settings data base management, with reconfirmation (manual or automatic) that the installed settings are correct whenever maintenance activity might have changed them; for background and guidance, see [5] in References.

Table 1 requires that settings must be verified to be as specified. The reason for this requirement is simple: With legacy relays (non-microprocessor protective relays), it is necessary to know the value of the intended setting in order to test, adjust and calibrate the relay. Proving that the relay works per specified setting was the de facto procedure. However, with the advanced microprocessor relays, it is possible to change relay settings for the purpose of verifying specific functions and then neglect to return the settings to the specified values. While there is no specific requirement to maintain a settings management process, there remains a need to verify that the settings left in the relay are the intended, specified settings. This need may manifest itself after any of the following:

- One or more settings are changed for any reason.
- A relay fails and is repaired or replaced with another unit.
- A relay is upgraded with a new firmware version.

12.1 Frequently Asked Questions:

How do I approach testing when I have to upgrade firmware of a microprocessor relay?

The entity should ensure that the relay continues to function properly after implementation of firmware changes. Some entities may have a R&D department that might routinely run acceptance tests on devices with firmware upgrades before allowing the upgrade to be installed. Other entities may rely upon the vigorous testing of the firmware OEM. An entity has the latitude to install devices and/or programming that they believe will perform to their satisfaction. If an entity should choose to perform the maintenance activities specified in the Tables following a firmware upgrade, then they may, if they choose, reset the time clock on that set of maintenance activities so that they would not have to repeat the maintenance on its regularly scheduled cycle.

(However, for simplicity in maintenance schedules, some entities may choose to not reset this time clock; it is merely a suggested option.)

If I upgrade my old relays, then do I have to maintain my previous equipment maintenance documentation?

If an equipment item is repaired or replaced, then the entity can restart the maintenance-activity-time-interval-clock, if desired; however, the replacement of equipment does not remove any documentation requirements. The requirements in the standard are intended to ensure that an entity has a maintenance plan, and that the entity adheres to minimum activities and maximum time intervals. The documentation requirements are intended to help an entity demonstrate compliance. For example, saving the dates and records of the last two maintenance activities is intended to demonstrate compliance with the interval. Therefore, if you upgrade or replace equipment, then you still must maintain the documentation for the previous equipment, thus demonstrating compliance with the time interval requirement prior to the replacement action.

We have a number of installations where we have changed our Protection System components. Some of the changes were upgrades, but others were simply system rating changes that merely required taking relays "out-of-service". What are our responsibilities when it comes to "out-of-service" devices?

Assuming that your system up-rates, upgrades and overall changes meet any and all other requirements and standards, then the requirements of PRC-005-X are simple – if the Protection System component performs a Protection System function, then it must be maintained. If the component no longer performs Protection System functions, then it does not require maintenance activities under the Tables of PRC-005-X. While many entities might physically remove a component that is no longer needed, there is no requirement in PRC-005-X to remove such component(s). Obviously, prudence would dictate that an "out-of-service" device is truly made inactive. There are no record requirements listed in PRC-005-X for Protection System components not used.

While performing relay testing of a protective device on our Bulk Electric System, it was discovered that the protective device being tested was either broken or out of calibration. Does this satisfy the relay testing requirement, even though the protective device tested bad, and may be unable to be placed back into service?

Yes, PRC-005-X requires entities to perform relay testing on protective devices on a given maintenance cycle interval. By performing this testing, the entity has satisfied PRC-005-X requirement, although the protective device may be unable to be returned to service under normal calibration adjustments. R5 states:

"R5. Each Transmission Owner, Generator Owner, and Distribution Provider shall demonstrate efforts to correct any identified Unresolved Maintenance Issues."

Also, when a failure occurs in a Protection System, power system security may be comprised, and notification of the failure must be conducted in accordance with relevant NERC standards.

If I show the protective device out of service while it is being repaired, then can I add it back as a new protective device when it returns? If not, my relay testing history would show that I was out of compliance for the last maintenance cycle.

The maintenance and testing requirements (R5) state "…shall demonstrate efforts to correct any identified Unresolved Maintenance Issues..." The type of corrective activity is not stated; however, it could include repairs or replacements.

Your documentation requirements will increase, of course, to demonstrate that your device tested bad and had corrective actions initiated. Your regional entity might ask about the status of your corrective actions.

13. Self-Monitoring Capabilities and Limitations

Microprocessor relay proponents have cited the self-monitoring capabilities of these products for nearly 20 years. Theoretically, any element that is monitored does not need a periodic manual test. A problem today is that the community of manufacturers and users has not created clear documentation of exactly what is and is not monitored. Some unmonitored but critical elements are buried in installed systems that are described as self-monitoring.

To utilize the extended time intervals allowed by monitoring, the user must document that the monitoring attributes of the device match the minimum requirements listed in the Table 1.

Until users are able to document how all parts of a system which are required for the protective functions are monitored or verified (with help from manufacturers), they must continue with the unmonitored intervals established in Table 1 and Table 3.

Going forward, manufacturers and users can develop mappings of the monitoring within relays, and monitoring coverage by the relay of user circuits connected to the relay terminals.

To enable the use of the most extensive monitoring (and never again have a hands-on maintenance requirement), the manufacturers of the microprocessor-based self-monitoring components in the Protection System should publish for the user a document or map that shows:

- How all internal elements of the product are monitored for any failure that could impact Protection System performance.
- Which connected circuits are monitored by checks implemented within the product; how to connect and set the product to assure monitoring of these connected circuits; and what circuits or potential problems are not monitored.

This manufacturer's information can be used by the registered entity to document compliance of the monitoring attributes requirements by:

- Presenting or referencing the product manufacturer's documents.
- Explaining in a system design document the mapping of how every component and circuit that is critical to protection is monitored by the microprocessor product(s) or by other design features.
- Extending the monitoring to include the alarm transmission Facilities through which failures are reported within a given time frame to allocate where action can be taken to initiate resolution of the alarm attributed to an Unresolved Maintenance Issue, so that failures of monitoring or alarming systems also lead to alarms and action.
- Documenting the plans for verification of any unmonitored components according to the requirements of Table 1 and Table 3.

13.1 Frequently Asked Questions:

I can't figure out how to demonstrate compliance with the requirements for the highest level of monitoring of Protection Systems. Why does this Maintenance Standard describe a maintenance program approach I cannot achieve?

Demonstrating compliance with the requirements for the highest level of monitoring any particular component of Protection Systems is likely to be very involved, and may include detailed manufacturer documentation of complete internal monitoring within a device, comprehensive design drawing reviews, and other detailed documentation. This standard does not presume to specify what documentation must be developed; only that it must be documented.

There may actually be some equipment available that is capable of meeting these highest levels of monitoring criteria, in which case it may be maintained according to the highest level of monitoring shown on the Tables. However, even if there is no equipment available today that can meet this level of monitoring, the standard establishes the necessary requirements for when such equipment becomes available.

By creating a roadmap for development, this provision makes the standard technology-neutral. The Standard Drafting Team wants to avoid the need to revise the standard in a few years to accommodate technology advances that may be coming to the industry.

14. Notification of Protection System or Automatic Reclosing Failures

When a failure occurs in a Protection System or Automatic Reclosing, power system security may be compromised, and notification of the failure must be conducted in accordance with relevant NERC standard(s). Knowledge of the failure may impact the system operator's decisions on acceptable Loading conditions.

This formal reporting of the failure and repair status to the system operator by the Protection System or Automatic Reclosing owner also encourages the system owner to execute repairs as rapidly as possible. In some cases, a microprocessor relay or carrier set can be replaced in hours; wiring termination failures may be repaired in a similar time frame. On the other hand, a component in an electromechanical or early-generation electronic relay may be difficult to find and may hold up repair for weeks. In some situations, the owner may have to resort to a temporary protection panel, or complete panel replacement.

15. Maintenance Activities

Some specific maintenance activities are a requirement to ensure reliability. An example would be that a BES entity could be prudent in its protective relay maintenance, but if its battery maintenance program is lacking, then reliability could still suffer. The NERC glossary outlines a Protection System as containing specific components. PRC-005-X requires specific maintenance activities be accomplished within a specific time interval. As noted previously, higher technology equipment can contain integral monitoring capability that actually performs maintenance verification activities routinely and often; therefore, *manual intervention* to perform certain activities on these type components may not be needed.

15.1 Protective Relays (Table 1-1)

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 Element of the BES. Devices that sense thermal, vibration, seismic, gas, or any other non-electrical inputs are excluded.

Non-microprocessor based equipment is treated differently than microprocessor-based equipment in the following ways; the relays should meet the asset owners' tolerances:

- Non-microprocessor devices must be tested with voltage and/or current applied to the device.
- Microprocessor devices may be tested through the integral testing of the device.
    - There is no specific protective relay commissioning test or relay routine test mandated.
    - There is no specific documentation mandated.

15.1.1 Frequently Asked Questions:

What calibration tolerance should be applied on electromechanical relays?

Each entity establishes their own acceptable tolerances when applying protective relaying on their system. For some Protection System components, adjustment is required to bring measurement accuracy within the parameters established by the asset owner based on the specific application of the component. A calibration failure is the result if testing finds the specified parameters to be out of tolerance.

15.2 Voltage & Current Sensing Devices (Table 1-3)

These are the current and voltage sensing devices, usually known as instrument transformers. There is presently a technology available (fiber-optic Hall-effect) that does not utilize conventional transformer technology; these devices and other technologies that produce quantities that represent the primary values of voltage and current are considered to be a type of voltage and current sensing devices included in this standard.

The intent of the maintenance activity is to verify the input to the protective relay from the device that produces the current or voltage signal sample.

There is no specific test mandated for these components. The important thing about these signals is to know that the expected output from these components actually reaches the protective relay. Therefore, the proof of the proper operation of these components also demonstrates the integrity of the wiring (or other medium used to convey the signal) from the current and voltage sensing device, all the way to the protective relay. The following observations apply:

- There is no specific ratio test, routine test or commissioning test mandated.
- There is no specific documentation mandated.
- It is required that the signal be present at the relay.
- This expectation can be arrived at from any of a number of means; including, but not limited to, the following: By calculation, by comparison to other circuits, by commissioning tests, by thorough inspection, or by any means needed to verify the circuit meets the asset owner's Protection System maintenance program.
- An example of testing might be a saturation test of a CT with the test values applied at the relay panel; this, therefore, tests the CT, as well as the wiring from the relay all the back to the CT.
- Another possible test is to measure the signal from the voltage and/or current sensing devices, during Load conditions, at the input to the relay.
- Another example of testing the various voltage and/or current sensing devices is to query the microprocessor relay for the Real-time Loading; this can then be compared to other devices to verify the quantities applied to this relay. Since the input devices have supplied the proper values to the protective relay, then the verification activity has been satisfied. Thus, event reports (and oscillographs) can be used to verify that the voltage and current sensing devices are performing satisfactorily.
- Still another method is to measure total watts and VArs around the entire bus; this should add up to zero watts and zero VArs, thus proving the voltage and/or current sensing devices system throughout the bus.
- Another method for proving the voltage and/or current-sensing devices is to complete commissioning tests on all of the transformers, cabling, fuses and wiring.
- Any other method that verifies the input to the protective relay from the device that produces the current or voltage signal sample.

15.2.1 Frequently Asked Questions:

What is meant by "…verify the current and voltage circuit inputs from the voltage and current sensing devices to the protective relays …" Do we need to perform ratio, polarity and saturation tests every few years?

No. You must verify that the protective relay is receiving the expected values from the voltage and current-sensing devices (typically voltage and current transformers). This can be as difficult as is proposed by the question (with additional testing on the cabling and substation wiring to ensure that the values arrive at the relays); or simplicity can be achieved by other verification methods. While some examples follow, these are not intended to represent an all-inclusive list; technology advances and ingenuity should not be excluded from making comparisons and verifications:

- Compare the secondary values, at the relay, to a metering circuit, fed by different current transformers, monitoring the same line as the questioned relay circuit.
- Compare the individual phase secondary values at the relay panel (with additional testing on the panel wiring to ensure that the values arrive at those relays) with the other phases, and verify that residual currents are within expected bounds.
- Observe all three phase currents and the residual current at the relay panel with an oscilloscope, observing comparable magnitudes and proper phase relationship, with additional testing on the panel wiring to ensure that the values arrive at the relays.
- Compare the values, as determined by the questioned relay (such as, but not limited to, a query to the microprocessor relay) to another protective relay monitoring the same line, with currents supplied by different CTs.
- Compare the secondary values, at the relay with values measured by test instruments (such as, but not limited to multi-meters, voltmeter, clamp-on ammeters, etc.) and verified by calculations and known ratios to be the values expected. For example, a single PT on a 100KV bus will have a specific secondary value that, when multiplied by the PT ratio, arrives at the expected bus value of 100KV.
- Query SCADA for the power flows at the far end of the line protected by the questioned relay, compare those SCADA values to the values as determined by the questioned relay.
- Totalize the Watts and VARs on the bus and compare the totals to the values as seen by the questioned relay.

The point of the verification procedure is to ensure that all of the individual components are functioning properly; and that an ongoing proactive procedure is in place to re-check the various components of the protective relay measuring Systems.

Is wiring insulation or hi-pot testing required by this Maintenance Standard?

No, wiring insulation and equipment hi-pot testing are not specifically required by the Maintenance Standard. However, if the method of verifying CT and PT inputs to the relay involves some other method than actual observation of current and voltage transformer secondary inputs to the relay, it might be necessary to perform some sort of cable integrity test to verify that the instrument transformer secondary signals are actually making it to the relay and not being shunted off to ground. For instance, you could use CT excitation tests and PT turns ratio tests

and compare to baseline values to verify that the instrument transformer outputs are acceptable. However, to conclude that these acceptable transformer instrument output signals are actually making it to the relay inputs, it also would be necessary to verify the insulation of the wiring between the instrument transformer and the relay.

My plant generator and transformer relays are electromechanical and do not have metering functions, as do microprocessor- based relays. In order for me to compare the instrument transformer inputs to these relays to the secondary values of other metered instrument transformers monitoring the same primary voltage and current signals, it would be necessary to temporarily connect test equipment, like voltmeters and clamp on ammeters, to measure the input signals to the relays. This practice seems very risky, and a plant trip could result if the technician were to make an error while measuring these current and voltage signals. How can I avoid this risk? Also, what if no other instrument transformers are available which monitor the same primary voltage or current signal?

Comparing the input signals to the relays to the outputs of other independent instrument transformers monitoring the same primary current or voltage is just one method of verifying the instrument transformer inputs to the relays, but is not required by the standard. Plants can choose how to best manage their risk. If online testing is deemed too risky, offline tests, such as, but not limited to, CT excitation test and PT turns ratio tests can be compared to baseline data and be used in conjunction with CT and PT secondary wiring insulation verification tests to adequately "verify the current and voltage circuit inputs from the voltage and current sensing devices to the protective relays …" while eliminating the risk of tripping an in service generator or transformer. Similarly, this same offline test methodology can be used to verify the relay input voltage and current signals to relays when there are no other instrument transformers monitoring available for purposes of signal comparison.

15.3 Control circuitry associated with protective functions (Table 1-5)

This component of Protection Systems includes the trip coil(s) of the circuit breaker, circuit switcher or any other interrupting device. It includes the wiring from the batteries to the relays. It includes the wiring (or other signal conveyance) from every trip output to every trip coil. It includes any device needed for the correct processing of the needed trip signal to the trip coil of the interrupting device; this requirement is meant to capture inputs and outputs to and from a protective relay that are necessary for the correct operation of the protective functions. In short, every trip path must be verified; the method of verification is optional to the asset owner. An example of testing methods to accomplish this might be to verify, with a volt-meter, the existence of the proper voltage at the open contacts, the open circuited input circuit and at the trip coil(s). As every parallel trip path has similar failure modes, each trip path from relay to trip coil must be verified. Each trip coil must be tested to trip the circuit breaker (or other interrupting device) at least once. There is a requirement to operate the circuit breaker (or other interrupting device) at least once every six years as part of the complete functional test. If a suitable monitoring system is installed that verifies every parallel trip path, then the manual-intervention testing of those parallel trip paths can be eliminated; however, the actual operation of the circuit breaker must still occur at least once every six years. This six-year tripping requirement can be completed as easily as tracking the Real-time Fault-clearing operations on the circuit breaker, or tracking the trip coil(s) operation(s) during circuit breaker routine maintenance actions.

The circuit-interrupting device should not be confused with a motor-operated disconnect. The intent of this standard is to require maintenance intervals and activities on Protection Systems equipment, and not just all system isolating equipment.

It is necessary, however, to classify a device that actuates a high-speed auto-closing ground switch as an interrupting device, if this ground switch is utilized in a Protection System and forces a ground Fault to occur that then results in an expected Protection System operation to clear the forced ground Fault. The SDT believes that this is essentially a transferred-tripping device without the use of communications equipment. If this high-speed ground switch is "…designed to provide protection for the BES…" then this device needs to be treated as any other Protection System component. The control circuitry would have to be tested within 12 years, and any electromechanically operated device will have to be tested every six years. If the spring-operated ground switch can be disconnected from the solenoid triggering unit, then the solenoid triggering unit can easily be tested without the actual closing of the ground blade.

The dc control circuitry also includes each auxiliary tripping relay (94) and each lock-out relay (86) that may exist in any particular trip scheme. If the lock-out relays (86) are electromechanical type components, then they must be trip tested. The PSMT SDT considers these components to share some similarities in failure modes as electromechanical protective relays; as such, there is a six-year maximum interval between mandated maintenance tasks unless PBM is applied.

Contacts of the 86 and/or 94 that pass the trip current on to the circuit interrupting device trip coils will have to be checked as part of the 12 year requirement. Contacts of the 86 and/or 94 lock relay that operate non-BES interrupting devices are not required. Normally-open contacts that are not used to pass a trip signal and normally-closed contacts do not have to be verified. Verification of the tripping paths is the requirement.

New technology is also accommodated here; there are some tripping systems that have replaced the traditional hard-wired trip circuitry with other methods of trip-signal conveyance such as fiber-optics. It is the intent of the PSMT SDT to include this, and any other, technology that is used to convey a trip signal from a protective relay to a circuit breaker (or other interrupting device) within this category of equipment. The requirement for these systems is verification of the tripping path.

Monitoring of the control circuit integrity allows for no maintenance activity on the control circuit (excluding the requirement to operate trip coils and electromechanical lockout and/or tripping auxiliary relays). Monitoring of integrity means to monitor for continuity and/or presence of voltage on each trip path. For Ethernet or fiber-optic control systems, monitoring of integrity means to monitor communication ability between the relay and the circuit breaker.

15.3.1 Frequently Asked Questions:

Is it permissible to verify circuit breaker tripping at a different time (and interval) than when we verify the protective relays and the instrument transformers?

Yes, provided the entire Protective System is tested within the individual component's maximum allowable testing intervals.

The Protection System Maintenance Standard describes requirements for verifying the tripping of circuit breakers. What is this telling me about maintenance of circuit breakers?

Requirements in PRC-005-X are intended to verify the integrity of tripping circuits, including the breaker trip coil, as well as the presence of auxiliary supply (usually a battery) for energizing the trip coil if a protection function operates. Beyond this, PRC-005-X sets no requirements for verifying circuit breaker performance, or for maintenance of the circuit breaker.

How do I test each dc Control Circuit trip path, as established in Table 1-5 "Protection System Control Circuitry (Trip coils and auxiliary relays)"?

Table 1-5 specifies that each breaker trip coil and lockout relays that carry trip current to a trip coil must be operated within the specified time period. The required operations may be via targeted maintenance activities, or by documented operation of these devices for other purposes such as Fault clearing.

Are high-speed ground switch trip coils included in the dc control circuitry?

Yes. PRC-005-X includes high-speed grounding switch trip coils within the dc control circuitry to the degree that the initiating Protection Systems are characterized as "transmission Protection Systems."

Does the control circuitry and trip coil of a non-BES breaker, tripped via a BES protection component, have to be tested per Table 1.5? (Refer to Table 3 for examples 1 and 2) Example 1: A non-BES circuit breaker that is tripped via a Protection System to which PRC-005-X applies might be (but is not limited to) a 12.5KV circuit breaker feeding (non-black-start) radial Loads but has a trip that originates from an under-frequency (81) relay.

- The relay must be verified.
- The voltage signal to the relay must be verified.
- All of the relevant dc supply tests still apply.
- The unmonitored trip circuit between the relay and any lock-out or auxiliary relay must be verified every 12 years.
- The unmonitored trip circuit between the lock-out (or auxiliary relay) and the non-BES breaker does not have to be proven with an electrical trip.
- In the case where there is no lock-out or auxiliary tripping relay used, the trip circuit to the non-BES breaker does not have to be proven with an electrical trip.
- The trip coil of the non-BES circuit breaker does not have to be individually proven with an electrical trip.

Example 2: A Transmission Owner may have a non-BES breaker that is tripped via a Protection System to which PRC-005-X applies, which may be (but is not limited to) a 13.8 KV circuit breaker feeding (non-black-start) radial Loads but has a trip that originates from a BES 115KV line relay.

- The relay must be verified
- The voltage signal to the relay must be verified
- All of the relevant dc supply tests still apply
- The unmonitored trip circuit between the relay and any lock-out (86) or auxiliary (94) relay must be verified every 12 years

- The unmonitored trip circuit between the lock-out (86) (or auxiliary (94)) relay and the non-BES breaker does not have to be proven with an electrical trip
- In the case where there is no lockout (86) or auxiliary (94) tripping relay used, the trip circuit to the non-BES breaker does not have to be proven with an electrical trip.
- The trip coil of the non-BES circuit breaker does not have to be individually proven with an electrical trip

Example 3: A Generator Owner may have a non-BES circuit breaker that is tripped via a Protection System to which PRC-005-X applies, such as the generator field breaker and low-side breakers on station service/excitation transformers connected to the generator bus.

Trip testing of the generator field breaker and low side station service/excitation transformer breaker(s) via lockout or auxiliary tripping relays are not required since these breakers may be associated with radially fed loads and are not considered to be BES breakers. An example of an otherwise non-BES circuit breaker that is tripped via a BES protection component might be (but is not limited to) a 6.9kV station service transformer source circuit breaker but has a trip that originates from a generator differential (87) relay.

- The differential relay must be verified.
- The current signals to the relay must be verified.
- All of the relevant dc supply tests still apply.
- The unmonitored trip circuit between the relay and any lock-out or auxiliary relay must be verified every 12 years.
- The unmonitored trip circuit between the lock-out (or auxiliary relay) and the non-BES breaker does not have to be proven with an electrical trip.
- In the case where there is no lock-out or auxiliary tripping relay used, the trip circuit to the non-BES breaker does not have to be proven with an electrical trip.
- The trip coil of the non-BES circuit breaker does not have to be individually proven with an electrical trip.

However, it is very prudent to verify the tripping of such breakers for the integrity of the overall generation plant.

Do I have to verify operation of breaker “a” contacts or any other normally closed auxiliary contacts in the trip path of each breaker as part of my control circuit test?

Operation of normally-closed contacts does not have to be verified. Verification of the tripping paths is the requirement. The continuity of the normally closed contacts will be verified when the tripping path is verified.

15.4 Batteries and DC Supplies (Table 1-4)

The NERC definition of a Protection System is:

- Protective relays which respond to electrical quantities,
- Communications Systems necessary for correct operation of protective functions,
- Voltage and current sensing devices providing inputs to protective relays,

- Station dc supply associated with protective functions (including station batteries, battery chargers, and non-battery-based dc supply), and
- Control circuitry associated with protective functions through the trip coil(s) of the circuit breakers or other interrupting devices.

The station battery is not the only component that provides dc power to a Protection System. In the new definition for Protection System, "station batteries" are replaced with "station dc supply" to make the battery charger and dc producing stored energy devices (that are not a battery) part of the Protection System that must be maintained.

The PSMT SDT recognizes that there are several technological advances in equipment and testing procedures that allow the owner to choose how to verify that a battery string is free of open circuits. The term "continuity" was introduced into the standard to allow the owner to choose how to verify continuity of a battery set by various methods, and not to limit the owner to other conventional methods of showing continuity. Continuity, as used in Table 1-4 of the standard, refers to verifying that there is a continuous current path from the positive terminal of the station battery set to the negative terminal. Without verifying continuity of a station battery, there is no way to determine that the station battery is available to supply dc power to the station. An open battery string will be an unavailable power source in the event of loss of the battery charger.

Batteries cannot be a unique population segment of a Performance-Based Maintenance Program (PBM) because there are too many variables in the electrochemical process to completely isolate all of the performance-changing criteria necessary for using PBM on battery Systems. However, nothing precludes the use of a PBM process for any other part of a dc supply besides the batteries themselves.

15.4.1 Frequently Asked Questions:

What constitutes the station dc supply, as mentioned in the definition of Protective System?

The previous definition of Protection System includes batteries, but leaves out chargers. The latest definition includes chargers, as well as dc systems that do not utilize batteries. This revision of PRC-005-X is intended to capture these devices that were not included under the previous definition. The station direct current (dc) supply normally consists of two components: the battery charger and the station battery itself. There are also emerging technologies that provide a source of dc supply that does not include either a battery or charger.

Battery Charger - The battery charger is supplied by an available ac source. At a minimum, the battery charger must be sized to charge the battery (after discharge) and supply the constant dc load. In many cases, it may be sized also to provide sufficient dc current to handle the higher energy requirements of tripping breakers and switches when actuated by the protective relays in the Protection System.

Station Battery - Station batteries provide the dc power required for tripping and for supplying normal dc power to the station in the event of loss of the battery charger. There are several technologies of battery that require unique forms of maintenance as established in Table 1-4.

Emerging Technologies - Station dc supplies are currently being developed that use other energy storage technologies besides the station battery to prevent loss of the station dc supply when ac

power is lost. Maintenance of these station dc supplies will require different kinds of tests and inspections. Table 1-4 presents maintenance activities and maximum allowable testing intervals for these new station dc supply technologies. However, because these technologies are relatively new, the maintenance activities for these station dc supplies may change over time.

What did the PSMT SDT mean by "continuity" of the dc supply?

The PSMT SDT recognizes that there are several technological advances in equipment and testing procedures that allow the owner to choose how to verify that a battery string is free of open circuits. The term "continuity" was introduced into the standard to allow the owner to choose how to verify continuity (no open circuits) of a battery set by various methods, and not to limit the owner to other conventional methods of showing continuity – lack of an open circuit. Continuity, as used in Table 1-4 of the standard, refers to verifying that there is a continuous current path from the positive terminal of the station battery set to the negative terminal (no open circuit). Without verifying continuity of a station battery, there is no way to determine that the station battery is available to supply dc power to the station. Whether it is caused from an open cell or a bad external connection, an open battery string will be an unavailable power source in the event of loss of the battery charger.

The current path through a station battery from its positive to its negative connection to the dc control circuits is composed of two types of elements. These path elements are the electrochemical path through each of its cells and all of the internal and external metallic connections and terminations of the batteries in the battery set. If there is loss of continuity (an open circuit) in any part of the electrochemical or metallic path, the battery set will not be available for service. In the event of the loss of the ac source or battery charger, the battery must be capable of supplying dc current, both for continuous dc loads and for tripping breakers and switches. Without continuity, the battery cannot perform this function.

At generating stations and large transmission stations where battery chargers are capable of handling the maximum current required by the Protection System, there are still problems that could potentially occur when the continuity through the connected battery is interrupted.

- Many battery chargers produce harmonics which can cause failure of dc power supplies in microprocessor-based protective relays and other electronic devices connected to station dc supply. In these cases, the substation battery serves as a filter for these harmonics. With the loss of continuity in the battery, the filter provided by the battery is no longer present.
- Loss of electrical continuity of the station battery will cause, in most battery chargers, regardless of the battery charger's output current capability, a delayed response in full output current from the charger. Almost all chargers have an intentional one- to two-second delay to switch from a low substation dc load current to the maximum output of the charger. This delay would cause the opening of circuit breakers to be delayed, which could violate system performance standards.

Monitoring of the station dc supply voltage will not indicate that there is a problem with the dc current path through the battery, unless the battery charger is taken out of service. At that time, a break in the continuity of the station battery current path will be revealed because there will be no voltage on the station dc circuitry. This particular test method, while proving battery continuity, may not be acceptable to all installations.

Although the standard prescribes what must be accomplished during the maintenance activity, it does not prescribe how the maintenance activity should be accomplished. There are several methods that can be used to verify the electrical continuity of the battery. These are not the only possible methods, simply a sampling of some methods:

- One method is to measure that there is current flowing through the battery itself by a simple clamp on milliamp-range ammeter. A battery is always either charging or discharging. Even when a battery is charged, there is still a measurable float charge current that can be detected to verify that there is continuity in the electrical path through the battery.
- A simple test for continuity is to remove the battery charger from service and verify that the battery provides voltage and current to the dc system. However, the behavior of the various dc-supplied equipment in the station should be considered before using this approach.
- Manufacturers of microprocessor-controlled battery chargers have developed methods for their equipment to periodically (or continuously) test for battery continuity. For example, one manufacturer periodically reduces the float voltage on the battery until current from the battery to the dc load can be measured to confirm continuity.
- Applying test current (as in some ohmic testing devices, or devices for locating dc grounds) will provide a current that when measured elsewhere in the string, will prove that the circuit is continuous.
- Internal ohmic measurements of the cells and units of lead-acid batteries (VRLA & VLA) can detect lack of continuity within the cells of a battery string; and when used in conjunction with resistance measurements of the battery's external connections, can prove continuity. Also some methods of taking internal ohmic measurements, by their very nature, can prove the continuity of a battery string without having to use the results of resistance measurements of the external connections.
- Specific gravity tests could infer continuity because without continuity there could be no charging occurring; and if there is no charging, then specific gravity will go down below acceptable levels over time.

No matter how the electrical continuity of a battery set is verified, it is a necessary maintenance activity that must be performed at the intervals prescribed by Table 1-4 to insure that the station dc supply has a path that can provide the required current to the Protection System at all times.

When should I check the station batteries to see if they have sufficient energy to perform as manufactured?

The answer to this question depends on the type of battery (valve-regulated lead-acid, vented lead-acid, or nickel-cadmium) and the maintenance activity chosen.

For example, if you have a valve-regulated lead-acid (VRLA) station battery, and you have chosen to evaluate the measured cell/unit internal ohmic values to the battery cell's baseline, you will have to perform verification at a maximum maintenance interval of no greater than every six months. While this interval might seem to be quite short, keep in mind that the six-

month interval is important for VRLA batteries; this interval provides an accumulation of data that better shows when a VRLA battery is incapable of performing as manufactured.

If, for a VRLA station battery, you choose to conduct a performance capacity test on the entire station battery as the maintenance activity, then you will have to perform verification at a maximum maintenance interval of no greater than every three calendar years.

How is a baseline established for cell/unit internal ohmic measurements?

Establishment of cell/unit internal ohmic baseline measurements should be completed when lead-acid batteries are newly installed. To ensure that the baseline ohmic cell/unit values are most indicative of the station battery's ability to perform as manufactured, they should be made at some point in time after the installation to allow the cell chemistry to stabilize after the initial freshening charge. An accepted industry practice for establishing baseline values is after six-months of installation, with the battery fully charged and in service. However, it is recommended that each owner, when establishing a baseline, should consult the battery manufacturer for specific instructions on establishing an ohmic baseline for their product, if available.

When internal ohmic measurements are taken, the same make/model test equipment should be used to establish the baseline and used for the future trending of the cells internal ohmic measurements because of variances in test equipment and the type of ohmic measurement used by different manufacturer's equipment. Keep in mind that one manufacturer's "Conductance" test equipment does not produce similar results as another manufacturer's "Conductance" test equipment, even though both manufacturers have produced "Ohmic" test equipment. Therefore, for meaningful results to an established baseline, the same make/model of instrument should be used.

For all new installations of valve-regulated lead-acid (VRLA) batteries and vented lead-acid (VLA) batteries, where trending of the cells internal ohmic measurements to a baseline are to be used to determine the ability of the station battery to perform as manufactured, the establishment of the baseline, as described above, should be followed at the time of installation to insure the most accurate trending of the cell/unit. However, often for older VRLA batteries, the owners of the station batteries have not established a baseline at installation. Also for owners of VLA batteries who want to establish a maintenance activity which requires trending of measured ohmic values to a baseline, there was typically no baseline established at installation of the station battery to trend to.

To resolve the problem of the unavailability of baseline internal ohmic measurements for the individual cell/unit of a station battery, many manufacturers of internal ohmic measurement devices have established libraries of baseline values for VRLA and VLA batteries using their testing device. Also, several of the battery manufacturers have libraries of baselines for their products that can be used to trend to. However, it is important that when using battery manufacturer-supplied data that it is verified that the baseline readings to be used were taken with the same ohmic testing device that will be used for future measurements (for example "Conductance Readings" from one manufacturer's test equipment do not correlate to "Impedance Readings" from a different manufacturer's test equipment). Although many manufacturers may have provided baseline values, which will allow trending of the internal ohmic measurements over the remaining life of a station battery, these baselines are not the actual cell/unit measurements for the battery being trended. It is important to have a baseline tailored to the station battery to more accurately use the tool of ohmic measurement trending. That more customized baseline

can only be created by following the establishment of a baseline for each cell/unit at the time of installation of the station battery.

Why determine the State of Charge?

Even though there is no present requirement to check the state of charge of a battery, it can be a very useful tool in determining the overall condition of a battery system. The following discussions are offered as a general reference.

When a battery is fully charged, the battery is available to deliver its existing capacity. As a battery is discharged, its ability to deliver its maximum available capacity is diminished. It is necessary to determine if the state of charge has dropped to an unacceptable level.

What is State of Charge and how can it be determined in a station battery?

The state of charge of a battery refers to the ratio of residual capacity at a given instant to the maximum capacity available from the battery. When a battery is fully charged, the battery is available to deliver its existing capacity. As a battery is discharged, its ability to deliver its maximum available capacity is diminished. Knowing the amount of energy left in a battery compared with the energy it had when it was fully charged gives the user an indication of how much longer a battery will continue to perform before it needs recharging.

For vented lead-acid (VLA) batteries which use accessible liquid electrolyte, a hydrometer can be used to test the specific gravity of each cell as a measure of its state of charge. The hydrometer depends on measuring changes in the weight of the active chemicals. As the battery discharges, the active electrolyte, sulfuric acid, is consumed and the concentration of the sulfuric acid in water is reduced. This, in turn, reduces the specific gravity of the solution in direct proportion to the state of charge. The actual specific gravity of the electrolyte can, therefore, be used as an indication of the state of charge of the battery. Hydrometer readings may not tell the whole story, as it takes a while for the acid to get mixed up in the cells of a VLA battery. If measured right after charging, you might see high specific gravity readings at the top of the cell, even though it is much less at the bottom. Conversely, if taken shortly after adding water to the cell, the specific gravity readings near the top of the cell will be lower than those at the bottom.

Nickel-cadmium batteries, where the specific gravity of the electrolyte does not change during battery charge and discharge, and valve-regulated lead-acid (VRLA) batteries, where the electrolyte is not accessible, cannot have their state of charge determined by specific gravity readings. For these two types of batteries, and for VLA batteries also, where another method besides taking hydrometer readings is desired, the state of charge may be determined by taking voltage and current readings at the battery terminals. The methods employed to obtain accurate readings vary for the different battery types. Manufacturers' information and IEEE guidelines can be consulted for specifics; (see IEEE 1106 Annex B for Nickel Cadmium batteries, IEEE 1188 Annex A for VRLA batteries and IEEE 450 for VLA batteries.

Why determine the Connection Resistance?

High connection resistance can cause abnormal voltage drop or excessive heating during discharge of a station battery. During periods of a high rate of discharge of the station battery, a very high resistance can cause severe damage. The maintenance requirement to verify battery terminal connection resistance in Table 1-4 is established to verify that the integrity of all battery electrical connections is acceptable. This verification includes cell-to-cell (intercell) and external

circuit terminations. Your method of checking for acceptable values of intercell and terminal connection resistance could be by individual readings, or a combination of the two. There are test methods presently that can read post termination resistances and resistance values between external posts. There are also test methods presently available that take a combination reading of the post termination connection resistance plus the intercell resistance value plus the post termination connection resistance value. Either of the two methods, or any other method, that can show if the adequacy of connections at the battery posts is acceptable.

Adequacy of the electrical terminations can be determined by comparing resistance measurements for all connections taken at the time of station battery's installation to the same resistance measurements taken at the maintenance interval chosen, not to exceed the maximum maintenance interval of Table 1-4. Trending of the interval measurements to the baseline measurements will identify any degradation in the battery connections. When the connection resistance values exceed the acceptance criteria for the connection, the connection is typically disassembled, cleaned, reassembled and measurements taken to verify that the measurements are adequate when compared to the baseline readings.

What conditions should be inspected for visible battery cells?

The maintenance requirement to inspect the cell condition of all station battery cells where the cells are visible is a maintenance requirement of Table 1-4. Station batteries are different from any other component in the Protection Station because they are a perishable product due to the electrochemical process which is used to produce dc electrical current and voltage. This inspection is a detailed visual inspection of the cells for abnormalities that occur in the aging process of the cell. In VLA battery visual inspections, some of the things that the inspector is typically looking for on the plates are signs of sulfation of the plates, abnormal colors (which are an indicator of sulfation or possible copper contamination) and abnormal conditions such as cracked grids. The visual inspection could look for symptoms of hydration that would indicate that the battery has been left in a completely discharged state for a prolonged period. Besides looking at the plates for signs of aging, all internal connections, such as the bus bar connection to each plate, and the connections to all posts of the battery need to be visually inspected for abnormalities. In a complete visual inspection for the condition of the cell the cell plates, separators and sediment space of each cell must be looked at for signs of deterioration. An inspection of the station battery's cell condition also includes looking at all terminal posts and cell-to-cell electric connections to ensure they are corrosion free. The case of the battery containing the cell, or cells, must be inspected for cracks and electrolyte leaks through cracks and the post seals.

This maintenance activity cannot be extended beyond the maximum maintenance interval of Table 1-4 by a Performance-Based Maintenance Program (PBM) because of the electrochemical aging process of the station battery, nor can there be any monitoring associated with it because there must be a visual inspection involved in the activity. A remote visual inspection could possibly be done, but its interval must be no greater than the maximum maintenance interval of Table 1-4.

Why is it necessary to verify the battery string can perform as manufactured? I only care that the battery can trip the breaker, which means that the battery can perform as designed. I oversize my batteries so that even if the battery cannot perform as manufactured, it can still trip my breakers.

The fundamental answer to this question revolves around the concept of battery performance "as designed" vs. battery performance "as manufactured." The purpose of the various sections of Table 1-4 of this standard is to establish requirements for the Protection System owner to maintain the batteries, to ensure they will operate the equipment when there is an incident that requires dc power, and ensure the batteries will continue to provide adequate service until at least the next maintenance interval. To meet these goals, the correct battery has to be properly selected to meet the design parameters, and the battery has to deliver the power it was manufactured to provide.

When testing batteries, it may be difficult to determine the original design (i.e., load profile) of the dc system. This standard is not intended as a design document, and requirements relating to design are, therefore, not included.

Where the dc load profile is known, the best way to determine if the system will operate as designed is to conduct a service test on the battery. However, a service test alone might not fully determine if the battery is healthy. A battery with 50% capacity may be able to pass a service test, but the battery would be in a serious state of deterioration and could fail at some point in the near future.

To ensure that the battery will meet the required load profile and continue to meet the load profile until the next maintenance interval, the installed battery must be sized correctly (i.e., a correct design), and it must be in a good state of health. Since the design of the dc system is not within the scope of the standard, the only consistent and reliable method to ensure that the battery is in a good state of health is to confirm that it can perform as manufactured. If the battery can perform as manufactured and it has been designed properly, the system should operate properly until the next maintenance interval.

How do I verify the battery string can perform as manufactured?

Optimally, actual battery performance should be verified against the manufacturer's rating curves. The best practice for evaluating battery performance is via a performance test. However, due to both logistical and system reliability concerns, some Protection System owners prefer other methods to determine if a battery can perform as manufactured. There are several battery parameters that can be evaluated to determine if a battery can perform as manufactured. Ohmic measurements and float current are two examples of parameters that have been reported to assist in determining if a battery string can perform as manufactured.

The evaluation of battery parameters in determining battery health is a complex issue, and is not an exact science. This standard gives the user an opportunity to utilize other measured parameters to determine if the battery can perform as manufactured. It is the responsibility of the Protection System owner, however, to maintain a documented process that demonstrates the chosen parameter(s) and associated methodology used to determine if the battery string can perform as manufactured.

Whatever parameters are used to evaluate the battery (ohmic measurements, float current, float voltages, temperature, specific gravity, performance test, or combination thereof), the goal is to determine the value of the measurement (or the percentage change) at which the battery fails to perform as manufactured, or the point where the battery is deteriorating so rapidly that it will not perform as manufactured before the next maintenance interval.

This necessitates the need for establishing and documenting a baseline. A baseline may be required of every individual cell, a particular battery installation, or a specific make, model, or size of a cell. Given a consistent cell manufacturing process, it may be possible to establish a baseline number for the cell (make/model/type) and, therefore, a subsequent baseline for every installation would not be necessary. However, future installations of the same battery types should be spot-checked to ensure that your baseline remains applicable.

Consistent testing methods by trained personnel are essential. Moreover, it is essential that these technicians utilize the same make/model of ohmic test equipment each time readings are taken in order to establish a meaningful and accurate trend line against the established baseline. The type of probe and its location (post, connector, etc.) for the reading need to be the same for each subsequent test. The room temperature should be recorded with the readings for each test as well. Care should be taken to consider any factors that might lead a trending program to become invalid.

Float current along with other measureable parameters can be used in lieu of or in concert with ohmic measurement testing to measure the ability of a battery to perform as manufactured. The key to using any of these measurement parameters is to establish a baseline and the point where the reading indicates that the battery will not perform as manufactured.

The establishment of a baseline may be different for various types of cells and for different types of installations. In some cases, it may be possible to obtain a baseline number from the battery manufacturer, although it is much more likely that the baseline will have to be established after the installation is complete. To some degree, the battery may still be “forming” after installation; consequently, determining a stable baseline may not be possible until several months after the battery has been in service.

The most important part of this process is to determine the point where the ohmic reading (or other measured parameter(s)) indicates that the battery cannot perform as manufactured. That point could be an absolute number, an absolute change, or a percentage change of an established baseline.

Since there are no universally-accepted repositories of this information, the Protection System owner will have to determine the value/percentage where the battery cannot perform as manufactured (heretofore referred to as a failed cell). This is the most difficult and important part of the entire process.

To determine the point where the battery fails to perform as manufactured, it is helpful to have a history of a battery type, if the data includes the parameter(s) used to evaluate the battery's ability to perform as manufactured against the actual demonstrated performance/capacity of a battery/cell.

For example, when an ohmic reading has been recorded that the user suspects is indicating a failed cell, a performance test of that cell (or string) should be conducted in order to prove/quantify that the cell has failed. Through this process, the user needs to determine the ohmic value at which the performance of the cell has dropped below 80% of the manufactured, rated performance. It is likely that there may be a variation in ohmic readings that indicates a failed cell (possibly significant). It is prudent to use the most conservative values to determine the point at which the cell should be marked for replacement. Periodically, the user should demonstrate that an “adequate” ohmic reading equates to an adequate battery performance (>80% of capacity).

Similarly, acceptance criteria for "good" and "failed" cells should be established for other parameters such as float current, specific gravity, etc., if used to determine the ability of a battery to function as designed.

What happens if I change the make/model of ohmic test equipment after the battery has been installed for a period of time?

If a user decides to switch testers, either voluntarily or because the equipment is not supported/sold any longer, the user may have to establish a new base line and new parameters that indicate when the battery no longer performs as manufactured. The user always has a choice to perform a capacity test in lieu of establishing new parameters.

What are some of the differences between lead-acid and nickel-cadmium batteries?

There is a marked difference in the aging process of lead acid and nickel-cadmium station batteries. The difference in the aging process of these two types of batteries is chiefly due to the electrochemical process of the battery type. Aging and eventual failure of lead acid batteries is due to expansion and corrosion of the positive grid structure, loss of positive plate active material, and loss of capacity caused by physical changes in the active material of the positive plates. In contrast, the primary failure of nickel-cadmium batteries is due to the gradual linear aging of the active materials in the plates. The electrolyte of a nickel-cadmium battery only facilitates the chemical reaction (it functions only to transfer ions between the positive and negative plates), but is not chemically altered during the process like the electrolyte of a lead acid battery. A lead acid battery experiences continued corrosion of the positive plate and grid structure throughout its operational life while a nickel-cadmium battery does not.

Changes to the properties of a lead acid battery when periodically measured and trended to a baseline, can indicate aging of the grid structure, positive plate deterioration, or changes in the active materials in the plate.

Because of the clear differences in the aging process of lead acid and nickel-cadmium batteries, there are no significantly measurable properties of the nickel-cadmium battery that can be measured at a periodic interval and trended to determine aging. For this reason, Table 1-4(c) (Protection System Station dc supply Using nickel-cadmium [NiCad] Batteries) only specifies one minimum maintenance activity and associated maximum maintenance interval necessary to verify that the station battery can perform as manufactured by evaluating cell/unit measurements indicative of battery performance against the station battery baseline. This maintenance activity is to conduct a performance or modified performance capacity test of the entire battery bank.

Why in Table 1-4 of PRC-005-X is there a maintenance activity to inspect the structural intergrity of the battery rack?

The purpose of this inspection is to verify that the battery rack is correctly installed and has no deterioration that could weaken its structural integrity.
Because the battery rack is specifically manufactured for the battery that is mounted on it, weakening of its structural members by rust or corrosion can physically jeopardize the battery.

What is required to comply with the "Unintentional dc Grounds" requirement?

In most cases, the first ground that appears on a battery is not a problem. It is the unintentional ground that appears on the opposite pole that becomes problematic. Even then many systems

are designed to operate favorably under some unintentional DC ground situations. It is up to the owner of the Protection System to determine if corrective actions are needed on detected unintentional DC grounds. The standard merely requires that a check be made for the existence of Unintentional DC Grounds. Obviously, a "check-off" of some sort will have to be devised by the inspecting entity to document that a check is routinely done for Unintentional DC Grounds because of the possible consequences to the Protection System.

Where the standard refers to "all cells," is it sufficient to have a documentation method that refers to "all cells," or do we need to have separate documentation for every cell? For example, do I need 60 individual documented check-offs for good electrolyte level, or would a single check-off per bank be sufficient?

A single check-off per battery bank is sufficient for documentation, as long as the single check-off attests to checking all cells/units.

Does this standard refer to Station batteries or all batteries; for example, Communications Site Batteries?

This standard refers to Station Batteries. The drafting team does not believe that the scope of this standard refers to communications sites. The batteries covered under PRC-005-X are the batteries that supply the trip current to the trip coils of the interrupting devices that are a part of the Protection System. The SDT believes that a loss of power to the communications systems at a remote site would cause the communications systems associated with protective relays to alarm at the substation. At this point, the corrective actions can be initiated.

What are cell/unit internal ohmic measurements?

With the introduction of Valve-Regulated Lead-Acid (VRLA) batteries to station dc supplies in the 1980's several of the standard maintenance tools that are used on Vented Lead-Acid (VLA) batteries were unable to be used on this new type of lead-acid battery to determine its state of health. The only tools that were available to give indication of the health of these new VRLA batteries were voltage readings of the total battery voltage, the voltage of the individual cells and periodic discharge tests.

In the search for a tool for determining the health of a VRLA battery several manufacturers studied the electrical model of a lead acid battery's current path through its cell. The overall battery current path consists of resistance and inductive and capacitive reactance. The inductive reactance in the current path through the battery is so minuscule when compared to the huge capacitive reactance of the cells that it is often ignored in most circuit models of the battery cell. Taking the basic model of a battery cell manufacturers of battery test equipment have developed and marketed testing devices to take measurements of the current path to detect degradation in the internal path through the cell.

In the battery industry, these various types of measurements are referred to as ohmic measurements. Terms used by the industry to describe ohmic measurements are ac conductance, ac impedance, and dc resistance. They are defined by the test equipment providers and IEEE and refer to the method of taking ohmic measurements of a lead acid battery. For example, in one manufacturer's ac conductance equipment measurements are taken by applying a voltage of a known frequency and amplitude across a cell or battery unit and observing the ac current flow it produces in response to the voltage. A manufacturer of an ac impedance meter measures ac current of a known frequency and amplitude that is passed through the whole battery string and determines the impedances of each cell or unit by measuring the resultant ac

voltage drop across them. On the other hand, dc resistance of a cell is measured by a third manufacturer's equipment by applying a dc load across the cell or unit and measuring the step change in both the voltage and current to calculate the internal dc resistance of the cell or unit.

It is important to note that because of the rapid development of the market for ohmic measurement devices, there were no standards developed or used to mandate the test signals used in making ohmic measurements. Manufacturers using proprietary methods and applying different frequencies and magnitudes for their signals have developed a diversity of measurement devices. This diversity in test signals coupled with the three different types of ohmic measurements techniques (impedance conductance and resistance) make it impossible to always get the same ohmic measurement for a cell with different ohmic measurement devices. However, IEEE has recognized the great value for choosing one device for ohmic measurement, no matter who makes it or the method to calculate the ohmic measurement. The only caution given by IEEE and the battery manufacturers is that when trending the cells of a lead acid station battery consistent ohmic measurement devices should be used to establish the baseline measurement and to trend the battery set for its entire life.

For VRLA batteries both IEEE Standard 1188 (Maintenance, Testing and Replacement of VRLA Batteries) and IEEE Standard 1187 (Installation Design and Installation of VRLA Batteries) recognize the importance of the maintenance activity of establishing a baseline for "cell/unit internal ohmic measurements (impedance, conductance and resistance)" and trending them at frequent intervals over the life of the battery. There are extensive discussions about the need for taking these measurements in these standards. IEEE Standard 1188 requires taking internal ohmic values as described in Annex C4 during regular inspections of the station battery. For VRLA batteries IEEE Standard 1188 in talking about the necessity of establishing a baseline and trending it over time says, "…depending on the degree of change a performance test, cell replacement or other corrective action may be necessary…" (IEEE std 1188-2005, C.4 page 18).

For VLA batteries IEEE Standard 484 (Installation of VLA batteries) gives several guidelines about establishing baseline measurements on newly installed lead acid stationary batteries. The standard also discusses the need to look for significant changes in the ohmic measurements, the caution that measurement data will differ with each type of model of instrument used, and lists a number of factors that affect ohmic measurements.

At the beginning of the 21st century, EPRI conducted a series of extensive studies to determine the relationship of internal ohmic measurements to the capacity of a lead acid battery cell. The studies indicated that internal ohmic measurements were in fact a good indicator of a lead acid battery cell's capacity, but because users often were only interested in the total station battery capacity and the technology does not precisely predict overall battery capacity, if a user only needs "an accurate measure of the overall battery capacity," they should "perform a battery capacity test."

Prior to the EPRI studies some large and small companies which owned and maintained station dc supplies in NERC Protection Systems developed maintenance programs where trending of ohmic measurements of cells/units of the station's battery became the maintenance activity for determining if the station battery could perform as manufactured. By evaluation of the trending of the ohmic measurements over time, the owner could track the performance of the individual components of the station battery and determine if a total station battery or components of it

required capacity testing, removal, replacement or in many instances replacement of the entire station battery. By taking this condition based approach these owners have eliminated having to perform capacity testing at prescribed intervals to determine if a battery needs to be replaced and are still able to effectively determine if a station battery can perform as manufactured.

My VRLA batteries have multiple-cells within an individual battery jar (or unit); how am I expected to comply with the cell-to-cell ohmic measurement requirements on these units that I cannot get to?

Measurement of cell/unit (not all batteries allow access to "individual cells" some "units" or jars may have multiple cells within a jar) internal ohmic values of all types of lead acid batteries where the cells of the battery are not visible is a station dc supply maintenance activity in Table 1-4. In cases where individual cells in a multi-cell unit are inaccessible, an ohmic measurement of the entire unit may be made.

I have a concern about my batteries being used to support additional auxiliary loads beyond my protection control systems in a generation station. Is ohmic measurement testing sufficient for my needs?

While this standard is focused on addressing requirements for Protection Systems, if batteries are used to service other load requirements beyond that of Protection Systems (e.g. pumps, valves, inverter loads), the functional entity may consider additional testing to confirm that the capacity of the battery is sufficient to support all loads.

Why verify voltage?

There are two required maintenance activities associated with verification of dc voltages in Table 1-4. These two required activities are to verify station dc supply voltage and float voltage of the battery charger, and have different maximum maintenance intervals. Both of these voltage verification requirements relate directly to the battery charger maintenance.

The verification of the dc supply voltage is simply an observation of battery voltage to prove that the charger has not been lost or is not malfunctioning; a reading taken from the battery charger panel meter or even SCADA values of the dc voltage could be some of the ways that one could satisfy the requirements. Low battery voltage below float voltage indicates that the battery may be on discharge and, if not corrected, the station battery could discharge down to some extremely low value that will not operate the Protection System. High voltage, close to or above the maximum allowable dc voltage for equipment connected to the station dc supply indicates the battery charger may be malfunctioning by producing high dc voltage levels on the Protection System. If corrective actions are not taken to bring the high voltage down, the dc power supplies and other electronic devices connected to the station dc supply may be damaged. The maintenance activity of verifying the float voltage of the battery charger is not to prove that a charger is lost or producing high voltages on the station dc supply, but rather to prove that the charger is properly floating the battery within the proper voltage limits. As above, there are many ways that this requirement can be met.

Why check for the electrolyte level?

In vented lead-acid (VLA) and nickel-cadmium (NiCad) batteries the visible electrolyte level must be checked as one of the required maintenance activities that must be performed at an interval that is equal to or less than the maximum maintenance interval of Table 1-4. Because the electrolyte level in valve-regulated lead-acid (VRLA) batteries cannot be observed, there is no maintenance activity listed in Table 1-4 of the standard for checking the electrolyte level. Low

electrolyte level of any cell of a VLA or NiCad station battery is a condition requiring correction. Typically, the electrolyte level should be returned to an acceptable level for both types of batteries (VLA and NiCad) by adding distilled or other approved-quality water to the cell.

Often people confuse the interval for watering all cells required due to evaporation of the electrolyte in the station battery cells with the maximum maintenance interval required to check the electrolyte level. In many of the modern station batteries, the jar containing the electrolyte is so large with the band between the high and low electrolyte level so wide that normal evaporation which would require periodic watering of all cells takes several years to occur. However, because loss of electrolyte due to cracks in the jar, overcharging of the station battery, or other unforeseen events can cause rapid loss of electrolyte; the shorter maximum maintenance intervals for checking the electrolyte level are required. A low level of electrolyte in a VLA battery cell which exposes the tops of the plates can cause the exposed portion of the plates to accelerated sulfation resulting in loss of cell capacity. Also, in a VLA battery where the electrolyte level goes below the end of the cell withdrawal tube or filling funnel, gasses can exit the cell by the tube instead of the flame arrester and present an explosion hazard.

What are the parameters that can be evaluated in Tables 1-4(a) and 1-4(b)?

The most common parameter that is periodically trended and evaluated by industry today to verify that the station battery can perform as manufactured is internal ohmic cell/unit measurements.

In the mid-1990s, several large and small utilities began developing maintenance and testing programs for Protection System station batteries using a condition based maintenance approach of trending internal ohmic measurements to each station battery cell's baseline value. Battery owners use the data collected from this maintenance activity to determine (1) when a station battery requires a capacity test (instead of performing a capacity test on a predetermined, prescribed interval), (2) when an individual cell or battery unit should be replaced, or (3) based on the analysis of the trended data, if the station battery should be replaced without performing a capacity test.

Other examples of measurable parameters that can be periodically trended and evaluated for lead acid batteries are cell voltage, float current, connection resistance. However, periodically trending and evaluating cell/unit Ohmic measurements are the most common battery/cell parameters that are evaluated by industry to verify a lead acid battery string can perform as manufactured.

Why does it appear that there are two maintenance activities in Table 1-4(b) (for VRLA batteries) that appear to be the same activity and have the same maximum maintenance interval?

There are two different and distinct reasons for doing almost the same maintenance activity at the same interval for valve-regulated lead-acid (VRLA) batteries. The first similar activity for VRLA batteries (Table 1-4(b)) that has the same maximum maintenance interval is to "measure battery cell/unit internal ohmic values." Part of the reason for this activity is because the visual inspection of the cell condition is unavailable for VRLA batteries. Besides the requirement to measure the internal ohmic measurements of VRLA batteries to determine the internal health of the cell, the maximum maintenance interval for this activity is significantly shorter than the interval for vented lead-acid (VLA) due to some unique failure modes for VRLA batteries. Some

of the potential problems that VRLA batteries are susceptible to that do not affect VLA batteries are thermal runaway, cell dry-out, and cell reversal when one cell has a very low capacity.

The other similar activity listed in Table 1-4(b) is "…verify that the station battery can perform as manufactured by evaluating the measured cell/unit measurements indicative of battery performance (e.g. internal ohmic values) against the station battery baseline." This activity allows an owner the option to choose between this activity with its much shorter maximum maintenance interval or the longer maximum maintenance interval for the maintenance activity to "Verify that the station battery can perform as manufactured by conducting a performance or modified performance capacity test of the entire battery bank."

For VRLA batteries, there are two drivers for internal ohmic readings. The first driver is for a means to trend battery life. Trending against the baseline of VRLA cells in a battery string is essential to determine the approximate state of health of the battery. Ohmic measurement testing may be used as the mechanism for measuring the battery cells. If all the cells in the string exhibit a consistent trend line and that trend line has not risen above a specific deviation (e.g. 30%) over baseline for impedance tests or below baseline for conductance tests, then a judgment can be made that the battery is still in a reasonably good state of health and able to 'perform as manufactured.' It is essential that the specific deviation mentioned above is based on data (test or otherwise) that correlates the ohmic readings for a specific battery/tester combination to the health of the battery. This is the intent of the "perform **as** manufactured six-month test" at Row 4 on Table 1-4b.

The second big driver is VRLA batteries tendency for thermal runaway. This is the intent of the "thermal runaway test" at Row 2 on Table 1-4b. In order to detect a cell in thermal runaway, you need not necessarily have a formal trending program. When a single cell/unit changes significantly or significantly varies from the other cells (e.g. a doubling of resistance/impedance or a 50% decrease in conductance), there is a high probability that the cell/unit/string needs to be replaced as soon as possible. In other words, if the battery is 10 years old and all the cells have approached a significant change in ohmic values over baseline, then you have a battery which is approaching end of life. You need to get ready to buy a new battery, but you do not have to worry about an impending catastrophic failure. On the other hand, if the battery is five years old and you have one cell that has a markedly different ohmic reading than all the other cells, then you need to be worried that this cell is susceptible to thermal runaway. If the float (charging) current has risen significantly and the ohmic measurement has increased/decreased as described above then concern of catastrophic failure should trigger attention for corrective action.

If an entity elects to use a capacity test rather than a cell ohmic value trending program, this does not eliminate the need to be concerned about thermal runaway – the entity still needs to do the six-month readings and look for cells which are outliers in the string but they need not trend results against the factory/as new baseline. Some entities will not mind the extra administrative burden of having the ongoing trending program against baseline - others would rather just do the capacity test and not have to trend the data against baseline. Nonetheless, all entities must look for ohmic outliers on a six-month basis.

It is possible to accomplish both tasks listed (trend testing for capability and testing for thermal runaway candidates) with the very same ohmic test. It becomes an analysis exercise of watching the trend from baselines and watching for the oblique cell measurement.

In table 1-4(f) (Exclusions for Protection System Station dc Supply Monitoring Devices and Systems), must all component attributes listed in the table be met before an exclusion can be granted for a maintenance activity?

Table 1-4(f) was created by the drafting team to allow Protection System dc supply owners to obtain exclusions from periodic maintenance activities by using monitoring devices. The basis of the exclusions granted in the table is that the monitoring devices must incorporate the monitoring capability of microprocessor based components which perform continuous self-monitoring. For failure of the microprocessor device used in dc supply monitoring, the self-checking routine in the microprocessor must generate an alarm which will be reported within 24 hours of device failure to a location where corrective action can be initiated.

Table 1-4(f) lists 8 component attributes along with a specific periodic maintenance activity associated with each of the 8 attributes listed. If an owner of a station dc supply wants to be excluded from periodically performing one of the 8 maintenance activities listed in table 1-4(f), the owner must have evidence that the monitoring and alarming component attributes associated with the excluded maintenance activity are met by the self-checking microprocessor based device with the specific component attribute listed in the table 1-4(f).

For example if an owner of a VLA station battery does not want to "verify station dc supply voltage" every "4 calendar months" (see table 1-4(a)), the owner can install a monitoring and alarming device "with high and low voltage monitoring and alarming of the battery charger voltage to detect charger overvoltage and charger failure" and "no periodic verification of station dc supply voltage is required" (see table 1-4(f) first row). However, if for the same Protection System discussed above, the owner does not install "electrolyte level monitoring and alarming in every cell" and "unintentional dc ground monitoring and alarming" (see second and third rows of table 1-4(f)), the owner will have to "inspect electrolyte level and for unintentional grounds" every "4 calendar months" (see table 1-4(a)).

15.5 Associated communications equipment (Table 1-2)

The equipment used for tripping in a communications-assisted trip scheme is a vital piece of the trip circuit. Remote action causing a local trip can be thought of as another parallel trip path to the trip coil that must be tested. Besides the trip output and wiring to the trip coil(s), there is also a communications medium that must be maintained. Newer technologies now exist that achieve communications-assisted tripping without the conventional wiring practices of older technology. For example, older technologies may have included Frequency Shift Key methods. This technology requires that guard and trip levels be maintained. The actual tripping path(s) to the trip coil(s) may be tested as a parallel trip path within the dc control circuitry tests. Emerging technologies transfer digital information over a variety of carrier mediums that are then interpreted locally as trip signals. The requirements apply to the communicated signal needed for the proper operation of the protective relay trip logic or scheme. Therefore, this standard is applied to equipment used to convey both trip signals (permissive or direct) and block signals.

It was the intent of this standard to require that a test be performed on any communications-assisted trip scheme, regardless of the vintage of technology. The essential element is that the tripping (or blocking) occurs locally when the remote action has been asserted; or that the tripping (or blocking) occurs remotely when the local action is asserted. Note that the required testing can still be done within the concept of testing by overlapping segments. Associated communications equipment can be (but is not limited to) testing at other times and different frequencies as the protective relays, the individual trip paths and the affected circuit interrupting devices.

Some newer installations utilize digital signals over fiber-optics from the protective relays in the control house to the circuit interrupting device in the yard. This method of tripping the circuit breaker, even though it might be considered communications, must be maintained per the dc control circuitry maintenance requirements.

15.5.1 Frequently Asked Questions:

What are some examples of mechanisms to check communications equipment functioning?

For unmonitored Protection Systems, various types of communications systems will have different facilities for on-site integrity checking to be performed at least every four months during a substation visit. Some examples are, but not limited to:

- On-off power-line carrier systems can be checked by performing a manual carrier keying test between the line terminals, or carrier check-back test from one terminal.
- Systems which use frequency-shift communications with a continuous guard signal (over a telephone circuit, analog microwave system, etc.) can be checked by observing for a loss-of-guard indication or alarm. For frequency-shift power-line carrier systems, the guard signal level meter can also be checked.
- Hard-wired pilot wire line Protection Systems typically have pilot-wire monitoring relays that give an alarm indication for a pilot wire ground or open pilot wire circuit loop.
- Digital communications systems typically have a data reception indicator or data error indicator (based on loss of signal, bit error rate, or frame error checking).

For monitored Protection Systems, various types of communications systems will have different facilities for monitoring the presence of the communications channel, and activating alarms that can be monitored remotely. Some examples are, but not limited to:

- On-off power-line carrier systems can be shown to be operational by automated periodic power-line carrier check-back tests with remote alarming of failures.
- Systems which use a frequency-shift communications with a continuous guard signal (over a telephone circuit, analog microwave system, etc.) can be remotely monitored with a loss-of-guard alarm or low signal level alarm.
- Hard-wired pilot wire line Protection Systems can be monitored by remote alarming of pilot-wire monitoring relays.
- Digital communications systems can activate remotely monitored alarms for data reception loss or data error indications.
- Systems can be queried for the data error rates.

For the highest degree of monitoring of Protection Systems, the communications system must monitor all aspects of the performance and quality of the channel that show it meets the design performance criteria, including monitoring of the channel interface to protective relays.

- In many communications systems signal quality measurements, including signal-to-noise ratio, received signal level, reflected transmitter power or standing wave ratio, propagation delay, and data error rates are compared to alarm limits. These alarms are connected for remote monitoring.
- Alarms for inadequate performance are remotely monitored at all times, and the alarm communications system to the remote monitoring site must itself be continuously

monitored to assure that the actual alarm status at the communications equipment location is continuously being reflected at the remote monitoring site.

What is needed for the four-month inspection of communications-assisted trip scheme equipment?

The four-month inspection applies to unmonitored equipment. An example of compliance with this requirement might be, but is not limited to:

With each site visit, check that the equipment is free from alarms; check any metered signal levels, and that power is still applied. While this might be explicit for a particular type of equipment (i.e., FSK equipment), the concept should be that the entity verify that the communications equipment that is used in a Protection System is operable through a cursory inspection and site visit. This site visit can be eliminated on this particular example if the FSK equipment had a monitored alarm on Loss of Guard. Blocking carrier systems with auto checkbacks will present an alarm when the channel fails allowing a visual indication. With no auto checkback, the channel integrity will need to be verified by a manual checkback or a two ended signal check. This check could also be eliminated by bring the auto checkback failure alarm to the monitored central location.

Does a fiber optic I/O scheme used for breaker tripping or control within a station, for example - transmitting a trip signal or control logic between the control house and the breaker control cabinet, constitute a communications system?

This equipment is presently classified as being part of the Protection System control circuitry and tested per the portions of Table 1 applicable to "Protection System Control Circuitry", rather than those portions of the table applicable to communications equipment.

What is meant by "Channel" and "Communications Systems" in Table 1-2?

The transmission of logic or data from a relay in one station to a relay in another station for use in a pilot relay scheme will require a communications system of some sort. Typical relay communications systems use fiber optics, leased audio channels, power line carrier, and microwave. The overall communications system includes the channel and the associated communications equipment.

This standard refers to the "channel" as the medium between the transmitters and receivers in the relay panels such as a leased audio or digital communications circuit, power line and power line carrier auxiliary equipment, and fiber. The dividing line between the channel and the associated communications equipment is different for each type of media.

Examples of the Channel:

- Power Line Carrier (PLC) - The PLC channel starts and ends at the PLC transmitter and receiver output unless there is an internal hybrid. The channel includes the external hybrids, tuners, wave traps and the power line itself.
- Microwave –The channel includes the microwave multiplexers, radios, antennae and associated auxiliary equipment. The audio tone and digital transmitters and receivers in the relay panel are the associated communications equipment.
- Digital/Audio Circuit – The channel includes the equipment within and between the substations. The associated communications equipment includes the relay panel transmitters and receivers and the interface equipment in the relays.

- Fiber Optic – The channel starts at the fiber optic connectors on the fiber distribution panel at the local station and goes to the fiber optic distribution panel at the remote substation. The jumpers that connect the relaying equipment to the fiber distribution panel and any optical-electrical signal format converters are the associated communications equipment

Figure 1-2, A-1 and A-2 at the end of this document show good examples of the communications channel and the associated communications equipment.

In Table 1-2, the Maintenance Activities section of the Protection System Communications Equipment and Channels refers to the quality of the channel meeting "performance criteria." What is meant by performance criteria?

Protection System communications channels must have a means of determining if the channel and communications equipment is operating normally. If the channel is not operating normally, an alarm will be indicated. For unmonitored systems, this alarm will probably be on the panel. For monitored systems, the alarm will be transmitted to a remote location.

Each entity will have established a nominal performance level for each Protection System communications channel that is consistent with proper functioning of the Protection System. If that level of nominal performance is not being met, the system will go into alarm. Following are some examples of Protection System communications channel performance measuring:

- For direct transfer trip using a frequency shift power line carrier channel, a guard level monitor is part of the equipment. A normal receive level is established when the system is calibrated and if the signal level drops below an established level, the system will indicate an alarm.

- An on-off blocking signal over power line carrier is used for directional comparison blocking schemes on transmission lines. During a Fault, block logic is sent to the remote relays by turning on a local transmitter and sending the signal over the power line to a receiver at the remote end. This signal is normally off so continuous levels cannot be checked. These schemes use check-back testing to determine channel performance. A predetermined signal sequence is sent to the remote end and the remote end decodes this signal and sends a signal sequence back. If the sending end receives the correct information from the remote terminal, the test passes and no alarm is indicated. Full power and reduced power tests are typically run. Power levels for these tests are determined at the time of calibration.

- Pilot wire relay systems use a hardwire communications circuit to communicate between the local and remote ends of the protective zone. This circuit is monitored by circulating a dc current between the relay systems. A typical level may be 1 mA. If the level drops below the setting of the alarm monitor, the system will indicate an alarm.

- Modern digital relay systems use data communications to transmit relay information to the remote end relays. An example of this is a line current differential scheme commonly used on transmission lines. The protective relays communicate current magnitude and phase information over the communications path to determine if the Fault is located in

the protective zone. Quantities such as digital packet loss, bit error rate and channel delay are monitored to determine the quality of the channel. These limits are determined and set during relay commissioning. Once set, any channel quality problems that fall outside the set levels will indicate an alarm.

The previous examples show how some protective relay communications channels can be monitored and how the channel performance can be compared to performance criteria established by the entity. This standard does not state what the performance criteria will be; it just requires that the entity establish nominal criteria so Protection System channel monitoring can be performed.

How is the performance criteria of Protection System communications equipment involved in the maintenance program?

An entity determines the acceptable performance criteria, depending on the technology implemented. If the communications channel performance of a Protection System varies from the pre-determined performance criteria for that system, then these results should be investigated and resolved.

How do I verify the A/D converters of microprocessor-based relays?

There are a variety of ways to do this. Two examples would be: using values gathered via data communications and automatically comparing these values with values from other sources, or using groupings of other measurements (such as vector summation of bus feeder currents) for comparison. Many other methods are possible.

15.6 Alarms (Table 2)

In addition to the tables of maintenance for the components of a Protection System, there is an additional table added for alarms. This additional table was added for clarity. This enabled the common alarm attributes to be consolidated into a single spot, and, thus, make it easier to read the Tables 1-1 through 1-5, Table 3, and Table 4. The alarms need to arrive at a site wherein a corrective action can be initiated. This could be a control room, operations center, etc. The alarming mechanism can be a standard alarming system or an auto-polling system; the only requirement is that the alarm be brought to the action-site within 24 hours. This effectively makes manned-stations equivalent to monitored stations. The alarm of a monitored point (for example a monitored trip path with a lamp) in a manned-station now makes that monitored point eligible for monitored status. Obviously, these same rules apply to a non-manned-station, which is that if the monitored point has an alarm that is auto-reported to the operations center (for example) within 24 hours, then it too is considered monitored.

15.6.1 Frequently Asked Questions:

Why are there activities defined for varying degrees of monitoring a Protection System component when that level of technology may not yet be available?

There may already be some equipment available that is capable of meeting the highest levels of monitoring criteria listed in the Tables. However, even if there is no equipment available today that can meet this level of monitoring the standard establishes the necessary requirements for when such equipment becomes available. By creating a roadmap for development, this provision makes the standard technology neutral. The Standard Drafting Team wants to avoid the need to revise the standard in a few years to accommodate technology advances that may be coming to the industry.

Does a fail-safe "form b" contact that is alarmed to a 24/7 operation center classify as an alarm path with monitoring?

If the fail-safe "form-b" contact that is alarmed to a 24/7 operation center causes the alarm to activate for failure of any portion of the alarming path from the alarm origin to the 24/7 operations center, then this can be classified as an alarm path with monitoring.

15.7 Distributed UFLS and Distributed UVLS Systems (Table 3)

Distributed UFLS and distributed UVLS systems have their maintenance activities documented in Table 3 due to their distributed nature allowing reduced maintenance activities and extended maximum maintenance intervals. Relays have the same maintenance activities and intervals as Table 1-1. Voltage and current-sensing devices have the same maintenance activity and interval as Table 1-3. DC systems need only have their voltage read at the relay every 12 years. Control circuits have the following maintenance activities every 12 years:

- Verify the trip path between the relay and lock-out and/or auxiliary tripping device(s).
- Verify operation of any lock-out and/or auxiliary tripping device(s) used in the trip circuit.
- No verification of trip path required between the lock-out (and/or auxiliary tripping device) and the non-BES interrupting device.
- No verification of trip path required between the relay and trip coil for circuits that have no lock-out and/or auxiliary tripping device(s).
- No verification of trip coil required.

No maintenance activity is required for associated communication systems for distributed UFLS and distributed UVLS schemes.

Non-BES interrupting devices that participate in a distributed UFLS or distributed UVLS scheme are excluded from the tripping requirement, and part of the control circuit test requirement; however, the part of the trip path control circuitry between the Load-Shed relay and lock-out or auxiliary tripping relay must be tested at least once every 12 years. In the case where there is no lock-out or auxiliary tripping relay used in a distributed UFLS or UVLS scheme which is not part of the BES, there is no control circuit test requirement. There are many circuit interrupting devices in the distribution system that will be operating for any given under-frequency event that requires tripping for that event. A failure in the tripping action of a single distributed system circuit breaker (or non-BES equipment interruption device) will be far less significant than, for example, any single transmission Protection System failure, such as a failure of a bus differential lock-out relay. While many failures of these distributed system circuit breakers (or non-BES equipment interruption device) could add up to be significant, it is also believed that many circuit breakers are operated often on just Fault clearing duty; and, therefore, these circuit breakers are operated at least as frequently as any requirements that appear in this standard.

There are times when a Protection System component will be used on a BES device, as well as a non-BES device, such as a battery bank that serves both a BES circuit breaker and a non-BES interrupting device used for UFLS. In such a case, the battery bank (or other Protection System component) will be subject to the Tables of the standard because it is used for the BES.

15.7.1 Frequently Asked Questions:

The standard reaches further into the distribution system than we would like for UFLS and UVLS

While UFLS and UVLS equipment are located on the distribution network, their job is to protect the Bulk Electric System. This is not beyond the scope of NERC's 215 authority.

FPA section 215(a) definitions section defines bulk power system as: "(A) facilities and control Systems necessary for operating an interconnected electric energy transmission network (or any portion thereof)." That definition, then, is limited by a later statement which adds the term bulk power system "…does not include facilities used in the local distribution of electric energy." Also, Section 215 also covers users, owners, and operators of bulk power Facilities.

UFLS and UVLS (when the UVLS is installed to prevent system voltage collapse or voltage instability for BES reliability) are not "used in the local distribution of electric energy," despite their location on local distribution networks. Further, if UFLS/UVLS Facilities were not covered by the reliability standards, then in order to protect the integrity of the BES during under-frequency or under-voltage events, that Load would have to be shed at the Transmission bus to ensure the Load-generation balance and voltage stability is maintained on the BES.

15.8 Automatic Reclosing (Table 4)

Please see the document referenced in Section F of PRC-005-3, "Considerations for Maintenance and Testing of Autoreclosing Schemes — November 2012", for a discussion of Automatic Reclosing as addressed in PRC-005-3.

15.8.1 Frequently-asked Questions

Automatic Reclosing is a control, not a protective function; why then is Automatic Reclosing maintenance included in the Protection System Maintenance Program (PSMP)?

Automatic Reclosing is a control function. The standard's title 'Protection System and Automatic Reclosing Maintenance' clearly distinguishes (separates) the Automatic Reclosing from the Protection System. Automatic Reclosing is included in the PSMP because it is a more pragmatic approach as compared to creating a parallel and essentially identical 'Control System Maintenance Program' for the two Automatic Reclosing component types.

Our maintenance practice consists of initiating the Automatic Reclosing relay and confirming the breaker closes properly and the close signal is released. This practice verifies the control circuitry associated with Automatic Reclosing. Do you agree?"

The described task partially verifies the control circuit maintenance activity. To meet the control circuit maintenance activity, responsible entities need to verify, *upon initiation*, that the reclosing relay does not issue a *premature closing command*. As noted on page 12 of the SAMS/SPCS report, the concern being addressed within the standard is premature autoreclosing that has the potential to cause generating unit or plant instability. Reclosing applications have many variations, responsible entities will need to verify the applicability of associated supervision/conditional logic and the reclosing relay operation; then verify the conditional logic or that the reclosing relay performs in a manner that does not result in a *premature closing command* being issued.

Some examples of conditions which can result in a premature closing command are: an improper supervision or conditional logic input which provides a false state and allows the reclosing relay to issue an improper close command based on incorrect conditions (i.e. voltage supervision, equipment status, sync window verification); timers utilized for closing actuation or reclosing arming/disarming circuitry which could allow the reclosing relay to issue an improper close command; a reclosing relay output contact failure which could result in a made-up-close condition / failure-to-release condition.

Why was a close-in three phase fault present for twice the normal clearing time chosen for the Automatic Reclosing exclusion? It exceeds TPL requirements and ignores the breaker closing time in a trip-close-trip sequence, thus making the exclusion harder to attain.

This condition represents a situation where a close signal is issued with no time delay or with less time delay than is intended, such as if a reclosing contact is welded closed. This failure mode can result in a minimum trip-close-trip sequence with the two faults cleared in primary protection operating time, and the open time between faults equal to the breaker closing cycle time. The sequence for this failure mode results in system impact equivalent to a high-speed autoreclosing sequence with no delay added in the autoreclosing logic. It represents a failure mode which must be avoided because it exceeds TPL requirements.

Do we have to test the various breaker closing circuit interlocks and controls such as anti-pump?

These components are not specifically addressed within Table 4, and need not be individually tested. They are indirectly verified by performing the Automatic Reclosing control circuitry verification as established in Table 4.

For Automatic Reclosing that <u>is not</u> part of an SPS, do we have to close the circuit breaker periodically?

No. For this application, you need only to verify that the Automatic Reclosing, upon initiation, does not issue a premature closing command. This activity is concerned only with assuring that a premature close does not occur, and cause generating plant instability.

For Automatic Reclosing that <u>is</u> part of an SPS, do we have to close the circuit breaker periodically?

Yes. In this application, successful closing is a necessary portion of the SPS, and must be verified.

15.9 Sudden Pressure Relaying (Table 5)

Please see the document referenced in Section F of PRC-005-X, "Sudden Pressure Relays and Other Devices that Respond to Non-Electrical Quantities – December 2013", for a discussion of Sudden Pressure Relaying as addressed in PRC-005-X.

15.9.1 Frequently Asked Questions:

How do I verify the pressure or flow sensing mechanism is operable?

Operate, or cause to operate the mechanism responding to the rapid-pressure rise. The standard does not specify how to perform the maintenance.

Why do I have to test the fault pressure relay every 6 years? Our experience is that these devices have no trouble operating as we have had our share of nuisance trips on through-faults.

The frequency of the testing is set to align with previously set maintenance intervals in PRC-005 and align with a survey of respondents as detailed in the previously noted NERC SPCS paper responding to FERC Order 758.

Sudden Pressure Relaying control circuitry is now specifically mentioned in the maintenance tables. Do we have to trip our circuit breaker specifically from the trip output of the sudden pressure relay?

No. Verification may be by breaker tripping, but may be verified in overlapping segments with the Protection System control circuitry.

Can we use Performance Based Maintenance for fault pressure relays?

Yes. Performance Based Maintenance is applicable to fault pressure relays.

15.10 Examples of Evidence of Compliance

To comply with the requirements of this standard, an entity will have to document and save evidence. The evidence can be of many different forms. The Standard Drafting Team recognizes that there are concurrent evidence requirements of other NERC standards that could, at times, fulfill evidence requirements of this standard.

15.10.1 Frequently Asked Questions:

What forms of evidence are acceptable?

Acceptable forms of evidence, as relevant for the requirement being documented include, but are not limited to:

- Process documents or plans
- Data (such as relay settings sheets, photos, SCADA, and test records)
- Database lists, records and/or screen shots that demonstrate compliance information
- Prints, diagrams and/or schematics
- Maintenance records
- Logs (operator, substation, and other types of log)
- Inspection forms
- Mail, memos, or email proving the required information was exchanged, coordinated, submitted or received
- Check-off forms (paper or electronic)
- Any record that demonstrates that the maintenance activity was known, accounted for, and/or performed.

If I replace a failed Protection System component with another component, what testing do I need to perform on the new component?

In order to reset the Table 1 maintenance interval for the replacement component, all relevant Table 1 activities for the component should be performed.

I have evidence to show compliance for PRC-016 ("Special Protection System Misoperation"). Can I also use it to show compliance for this Standard, PRC-005-X?

Maintaining evidence for operation of Special Protection Systems could concurrently be utilized as proof of the operation of the associated trip coil (provided one can be certain of the trip coil involved). Thus, the reporting requirements that one may have to do for the Misoperation of a Special Protection Scheme under PRC-016 could work for the activity tracking requirements under this PRC-005-X.

I maintain Disturbance records which show Protection System operations. Can I use these records to show compliance?

These records can be concurrently utilized as dc trip path verifications, to the degree that they demonstrate the proper function of that dc trip path.

I maintain test reports on some of my Protection System components. Can I use these test reports to show that I have verified a maintenance activity?

Yes.

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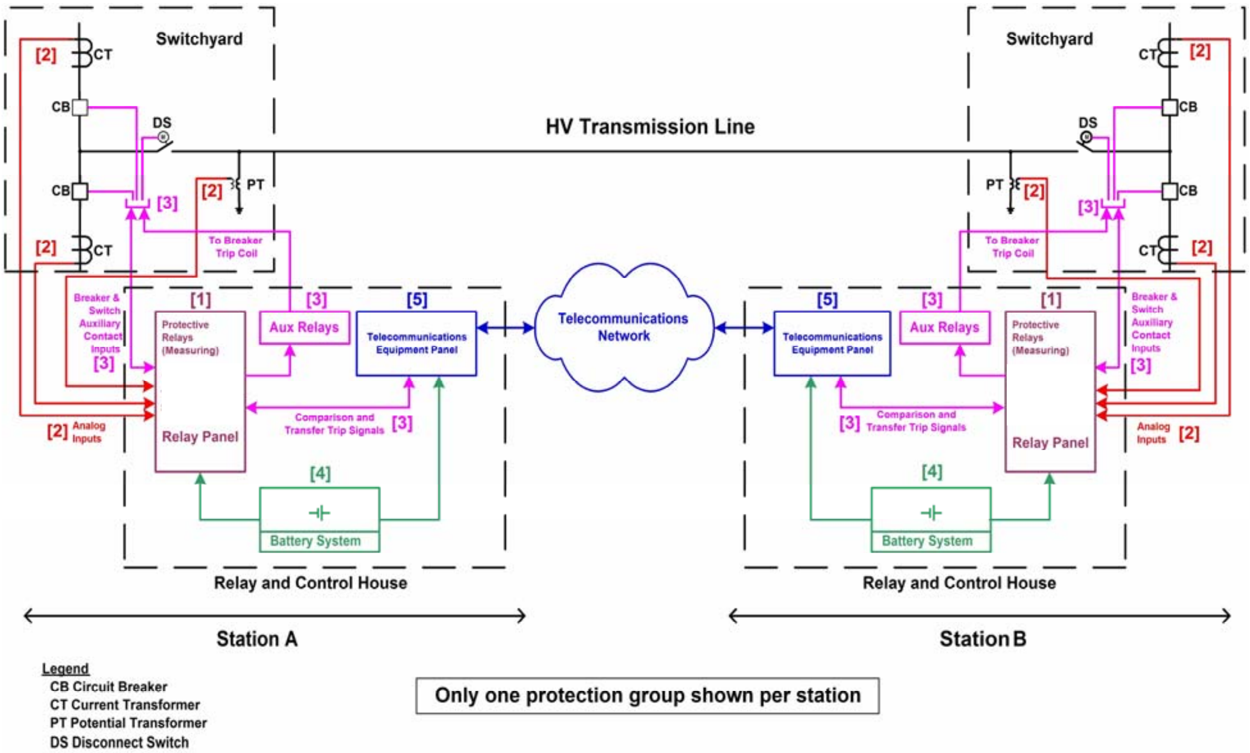
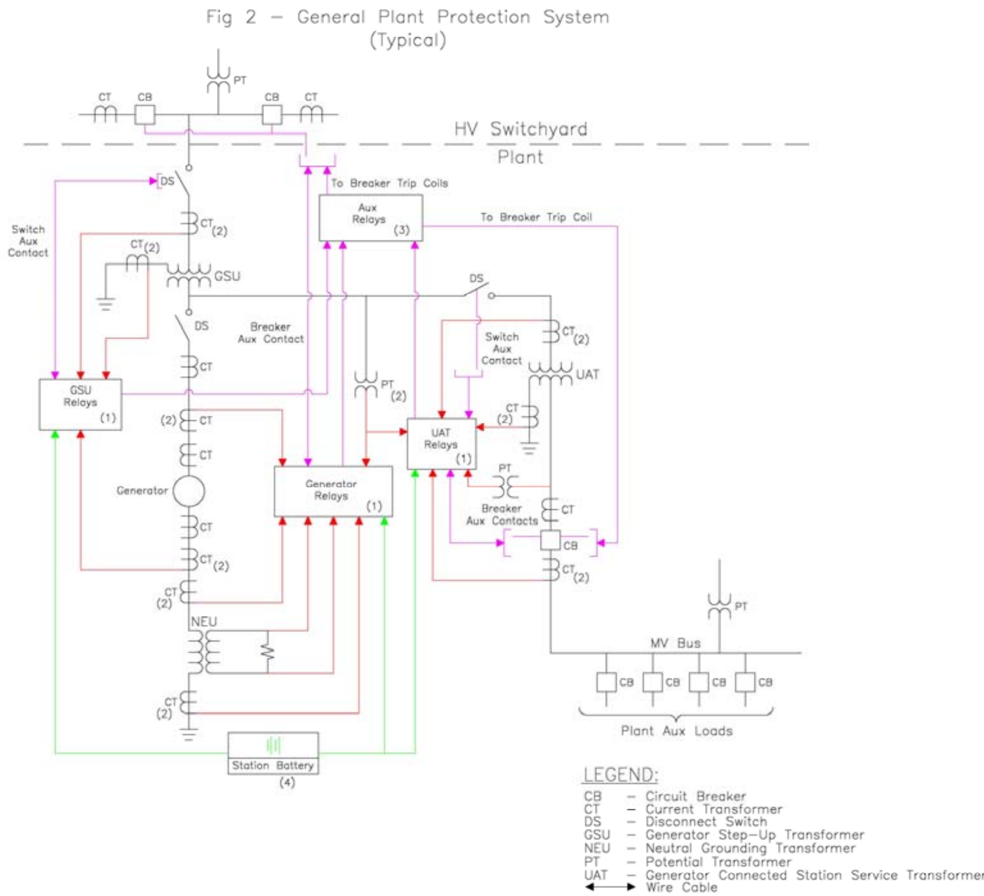
Figures

Figure 1: Typical Transmission System



For information on components, see ***[Figure 1 & 2 Legend – components of Protection Systems]()***

Figure 2: Typical Generation System



Note: Figure 2 may show elements that are not included within PRC-005-2, and also may not be all-inclusive; see the Applicability section of the standard for specifics.

For information on components, see ***Figure 1 & 2 Legend – components of Protection Systems***

Figure 1 & 2 Legend – Components of Protection Systems

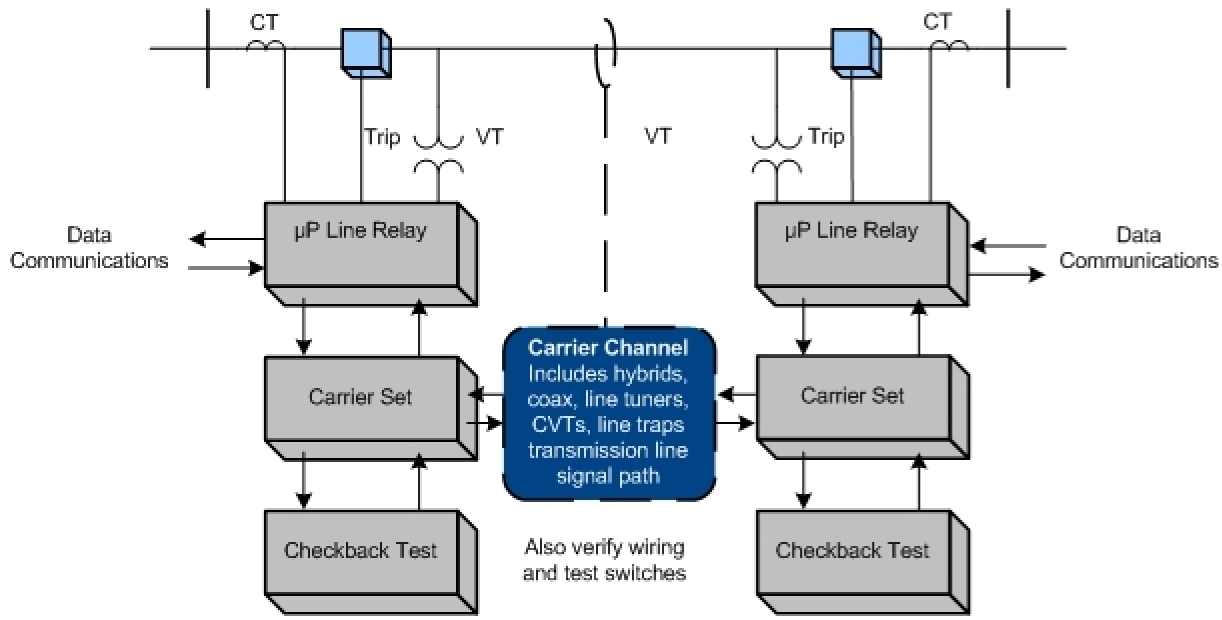
Number in Figure	Component of Protection System	Includes	Excludes
1	Protective relays which respond to electrical quantities	All protective relays that use current and/or voltage inputs from current & voltage sensors and that trip the 86, 94 or trip coil.	Devices that use non-electrical methods of operation including thermal, pressure, gas accumulation, and vibration. Any ancillary equipment not specified in the definition of Protection Systems. Control and/or monitoring equipment that is not a part of the automatic tripping action of the Protection System
2	Voltage and current sensing devices providing inputs to protective relays	The signals from the voltage & current sensing devices to the protective relay input.	Voltage & current sensing devices that are not a part of the Protection System, including sync-check systems, metering systems and data acquisition systems.
3	Control circuitry associated with protective functions	All control wiring (or other medium for conveying trip signals) associated with the tripping action of 86 devices, 94 devices or trip coils (from all parallel trip paths). This would include fiber-optic systems that carry a trip signal as well as hard-wired systems that carry trip current.	Closing circuits, SCADA circuits, other devices in control scheme not passing trip current
4	Station dc supply	Batteries and battery chargers and any control power system which has the function of supplying power to the protective relays, associated trip circuits and trip coils.	Any power supplies that are not used to power protective relays or their associated trip circuits and trip coils.
5	Communications systems necessary for correct operation of protective functions	Tele-protection equipment used to convey specific information, in the form of analog or digital signals, necessary for the correct operation of protective functions.	Any communications equipment that is not used to convey information necessary for the correct operation of protective functions.

[Additional information can be found in References]

Appendix A

The following illustrates the concept of overlapping verifications and tests as summarized in Section 10 of the paper. As an example, Figure A-1 shows protection for a critical transmission line by carrier blocking directional comparison pilot relaying. The goal is to verify the ability of the entire two-terminal pilot protection scheme to protect for line Faults, and to avoid over-tripping for Faults external to the transmission line zone of protection bounded by the current transformer locations.

Figure A-1



In this example (Figure A1), verification takes advantage of the self-monitoring features of microprocessor multifunction line relays at each end of the line. For each of the line relays themselves, the example assumes that the user has the following arrangements in place:

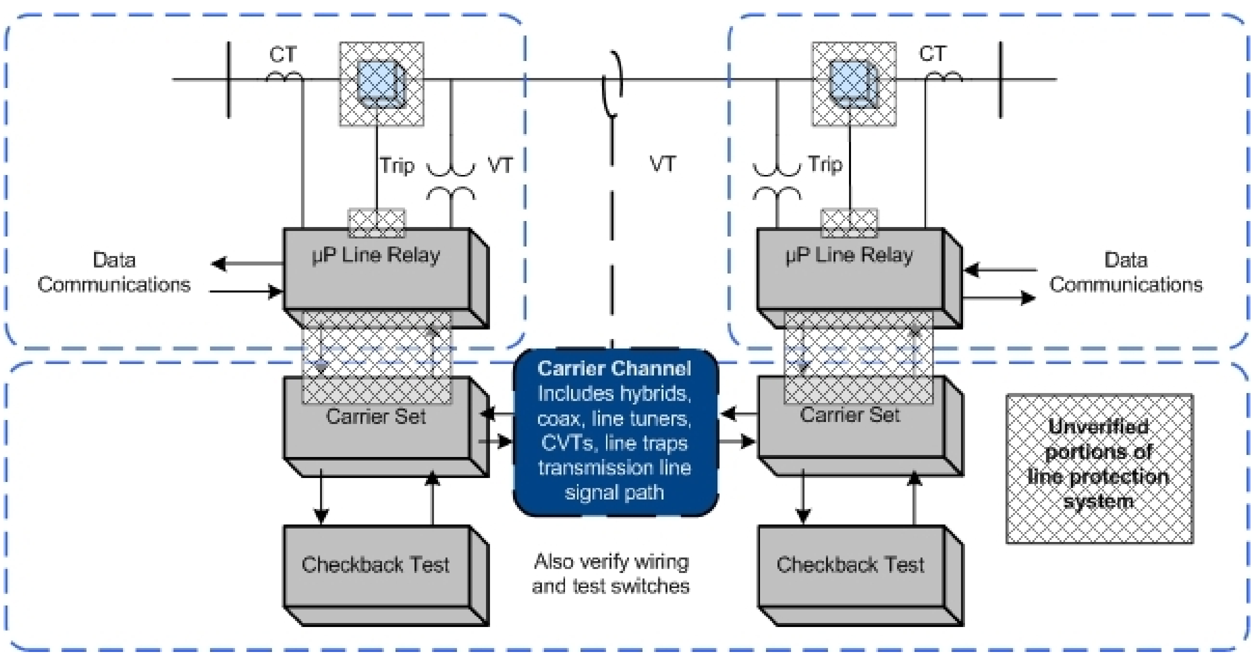
1. The relay has a data communications port that can be accessed from remote locations.
2. The relay has internal self-monitoring programs and functions that report failures of internal electronics, via communications messages or alarm contacts to SCADA.
3. The relays report loss of dc power, and the relays themselves or external monitors report the state of the dc battery supply.
4. The CT and PT inputs to the relays are used for continuous calculation of metered values of volts, amperes, plus Watts and VARs on the line. These metered values are reported by data communications. For maintenance, the user elects to compare these readings to those of other relays, meters, or DFRs. The other readings may be from redundant relaying or measurement systems or they may be derived from values in other protection zones. Comparison with other such readings to within required relaying accuracy verifies voltage & current sensing devices, wiring, and analog signal input processing of the relays. One

effective way to do this is to utilize the relay metered values directly in SCADA, where they can be compared with other references or state estimator values.

5. Breaker status indication from auxiliary contacts is verified in the same way as in (2). Status indications must be consistent with the flow or absence of current.
6. Continuity of the breaker trip circuit from dc bus through the trip coil is monitored by the relay and reported via communications.
7. Correct operation of the on-off carrier channel is also critical to security of the Protection System, so each carrier set has a connected or integrated automatic checkback test unit. The automatic checkback test runs several times a day. Newer carrier sets with integrated checkback testing check for received signal level and report abnormal channel attenuation or noise, even if the problem is not severe enough to completely disable the channel.

These monitoring activities plus the check-back test comprise automatic verification of all the Protection System elements that experience tells us are the most prone to fail. But, does this comprise a complete verification?

Figure A-2



The dotted boxes of Figure A-2 show the sections of verification defined by the monitoring and verification practices just listed. These sections are not completely overlapping, and the shaded regions show elements that are not verified:

1. The continuity of trip coils is verified, but no means is provided for validating the ability of the circuit breaker to trip if the trip coil should be energized.

2. Within each line relay, all the microprocessors that participate in the trip decision have been verified by internal monitoring. However, the trip circuit is actually energized by the contacts of a small telephone-type "ice cube" relay within the line protective relay. The microprocessor energizes the coil of this ice cube relay through its output data port and a transistor driver circuit. There is no monitoring of the output port, driver circuit, ice cube relay, or contacts of that relay. These components are critical for tripping the circuit breaker for a Fault.
3. The check-back test of the carrier channel does not verify the connections between the relaying microprocessor internal decision programs and the carrier transmitter keying circuit or the carrier receiver output state. These connections include microprocessor I/O ports, electronic driver circuits, wiring, and sometimes telephone-type auxiliary relays.
4. The correct states of breaker and disconnect switch auxiliary contacts are monitored, but this does not confirm that the state change indication is correct when the breaker or switch opens.

A practical solution for (1) and (2) is to observe actual breaker tripping, with a specified maximum time interval between trip tests. Clearing of naturally-occurring Faults are demonstrations of operation that reset the time interval clock for testing of each breaker tripped in this way. If Faults do not occur, manual tripping of the breaker through the relay trip output via data communications to the relay microprocessor meets the requirement for periodic testing.

PRC-005-X does not address breaker maintenance, and its Protection System test requirements can be met by energizing the trip circuit in a test mode (breaker disconnected) through the relay microprocessor. This can be done via a front-panel button command to the relay logic, or application of a simulated Fault with a relay test set. However, utilities have found that breakers often show problems during Protection System tests. It is recommended that Protection System verification include periodic testing of the actual tripping of connected circuit breakers.

Testing of the relay-carrier set interface in (3) requires that each relay key its transmitter, and that the other relay demonstrate reception of that blocking carrier. This can be observed from relay or DFR records during naturally occurring Faults, or by a manual test. If the checkback test sequence were incorporated in the relay logic, the carrier sets and carrier channel are then included in the overlapping segments monitored by the two relays, and the monitoring gap is completely eliminated.

Appendix B

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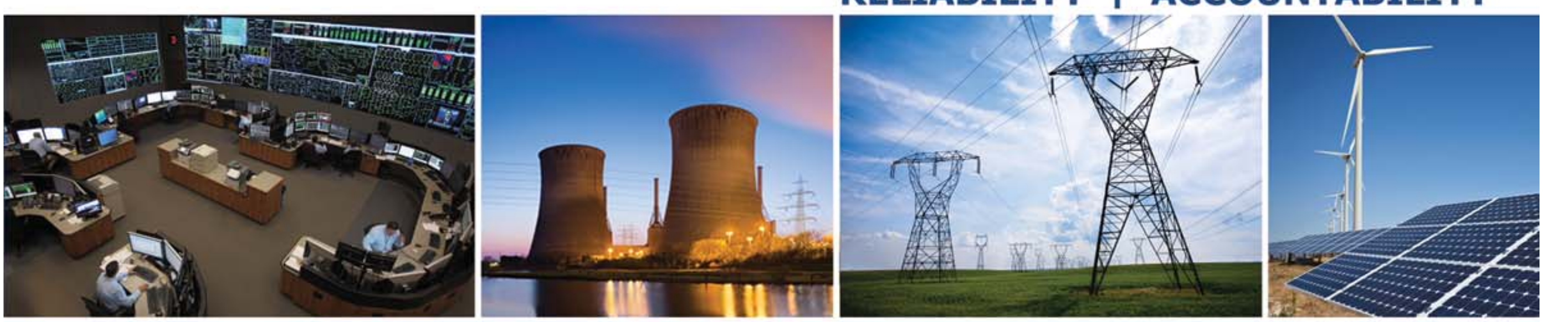
Supplementary Reference and FAQ

PRC-005-X Protection System Maintenance and Testing

July 2014

RELIABILITY | ACCOUNTABILITY



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1. Introduction and Summary

Note: This supplementary reference for PRC-005-X is neither mandatory nor enforceable.

NERC currently has four Reliability Standards that are mandatory and enforceable in the United States and Canada and address various aspects of maintenance and testing of Protection and Control Systems.

These standards are:

PRC-005-1b — Transmission and Generation Protection System Maintenance and Testing

PRC-008-0 — Underfrequency Load Shedding Equipment Maintenance Programs

PRC-011-0 — UVLS System Maintenance and Testing

PRC-017-0 — Special Protection System Maintenance and Testing

While these standards require that applicable entities have a maintenance program for Protection Systems, and that these entities must be able to demonstrate they are carrying out such a program, there are no specifics regarding the technical requirements for Protection System maintenance programs. Furthermore, FERC Order 693 directed additional modifications respective to Protection System maintenance programs. PRC-005-3 will replace PRC-005-2 which combined and replaced PRC-005, PRC-008, PRC-011 and PRC-017. PRC-005-3 adds Automatic Reclosing to PRC-005-2. PRC-005-2 addressed these directed modifications and replaces PRC-005, PRC-008, PRC-011 and PRC-017.

FERC Order 758 further directed that maintenance of reclosing relays and sudden pressure relays that affect the reliable operation of the Bulk Power System be addressed. PRC-005-3 addresses this directive regarding reclosing relays, and, when approved, will supersede PRC-005-2. PRC-005-X addresses this directive regarding sudden pressure relays and, when approved, will supersede PRC-005-3.

This document augments the Supplementary Reference and FAQ previously developed for PRC-005-2 by including discussion relevant to Automatic Reclosing added in PRC-005-3 and Sudden Pressure Relaying in PRC-005-X.

2. Need for Verifying Protection System Performance

Protective relays have been described as silent sentinels, and do not generally demonstrate their performance until a Fault or other power system problem requires that they operate to protect power system Elements, or even the entire Bulk Electric System (BES). Lacking Faults, switching operations or system problems, the Protection Systems may not operate, beyond static operation, for extended periods. A Misoperation - a false operation of a Protection System or a failure of the Protection System to operate, as designed, when needed - can result in equipment damage, personnel hazards, and wide-area Disturbances or unnecessary customer outages. Maintenance or testing programs are used to determine the performance and availability of Protection Systems.

Typically, utilities have tested Protection Systems at fixed time intervals, unless they had some incidental evidence that a particular Protection System was not behaving as expected. Testing practices vary widely across the industry. Testing has included system functionality, calibration of measuring devices, and correctness of settings. Typically, a Protection System must be visited at its installation site and, in many cases, removed from service for this testing.

Fundamentally, a Reliability Standard for Protection System Maintenance and Testing requires the performance of the maintenance activities that are necessary to detect and correct plausible age and service related degradation of the Protection System components, such that a properly built and commissioned Protection System will continue to function as designed over its service life.

Similarly station batteries, which are an important part of the station dc supply, are not called upon to provide instantaneous dc power to the Protection System until power is required by the Protection System to operate circuit breakers or interrupting devices to clear Faults or to isolate equipment.

2.1 Existing NERC Standards for Protection System Maintenance and Testing

For critical BES protection functions, NERC standards have required that each utility or asset owner define a testing program. The starting point is the existing Standard PRC-005, briefly restated as follows:

Purpose: To document and implement programs for the maintenance of all Protection Systems affecting the reliability of the Bulk Electric System (BES) so that these Protection Systems are kept in working order.

PRC-005-X is not specific on where the boundaries of the Protection Systems lie. However, the definition of Protection System in the NERC Glossary of Terms used in Reliability Standards indicates what must be included as a minimum.

At the beginning of the project to develop PRC-005-2, the definition of Protection System was:

Protective relays, associated communications Systems, voltage and current sensing devices, station batteries and dc control circuitry.

Applicability: Owners of generation and transmission Protection Systems.

Requirements: The owner shall have a documented maintenance program with test intervals. The owner must keep records showing that the maintenance was performed at the specified intervals.

2.2 Protection System Definition

The most recently approved definition of Protection Systems is:

- Protective relays which respond to electrical quantities,
- Communications systems necessary for correct operation of protective functions,
- Voltage and current sensing devices providing inputs to protective relays,
- Station dc supply associated with protective functions (including station batteries, battery chargers, and non-battery-based dc supply), and
- Control circuitry associated with protective functions through the trip coil(s) of the circuit breakers or other interrupting devices.

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:

"…that are installed for the purpose of detecting Faults on BES Elements (lines, buses, transformers, etc.)."

The drafting team intends that this standard will follow with any definition of the Bulk Electric System. There should be no ambiguity; if the Element is a BES Element, then the Protection System protecting that Element should then be included within this standard. If there is regional variation to the definition, then there will be a corresponding regional variation to the Protection Systems that fall under this standard.

There is no way for the Standard Drafting Team to know whether a specific 230KV line, 115KV line (even 69KV line), for example, should be included or excluded. Therefore, the team set the clear intent that the standard language should simply be applicable to Protection Systems for BES Elements.

The BES is a NERC defined term that, from time to time, may undergo revisions. Additionally, there may even be regional variations that are allowed in the present and future definitions. See the NERC Glossary of Terms for the present, in-force definition. See the applicable Regional Reliability Organization for any applicable allowed variations.

While this standard will undergo revisions in the future, this standard will not attempt to keep up with revisions to the NERC definition of BES, but, rather, simply make BES Protection Systems applicable.

The Standard is applied to Generator Owners (GO) and Transmission Owners (TO) because GOs and TOs have equipment that is BES equipment. The standard brings in Distribution Providers (DP) because, depending on the station configuration of a particular substation, there may be

Protection System equipment installed at a non-transmission voltage level (Distribution Provider equipment) that is wholly or partially installed to protect the BES. PRC-005-X would apply to this equipment. An example is underfrequency load-shedding, which is frequently applied well down into the distribution system to meet PRC-007-0.

PRC-005-2 replaced the existing PRC-005, PRC-008, PRC-011 and PRC-017. Much of the original intent of those standards was carried forward whenever it was possible to continue the intent without a disagreement with FERC Order 693. For example, the original PRC-008 was constructed quite differently than the original PRC-005. The drafting team agrees with the intent of this and notes that distributed tripping schemes would have to exhibit multiple failures to trip before they would prove to be significant, as opposed to a single failure to trip of, for example, a transmission Protection System Bus Differential lock-out relay. While many failures of these distribution breakers could add up to be significant, it is also believed that distribution breakers are operated often on just Fault clearing duty; and, therefore, the distribution circuit breakers are operated at least as frequently as stipulated in any requirement in this standard.

Additionally, since PRC-005-2 replaced PRC-011, it will be important to make the distinction between under-voltage Protection Systems that protect individual Loads and Protection Systems that are UVLS schemes that protect the BES. Any UVLS scheme that had been applicable under PRC-011 is now applicable under PRC-005-2. An example of an under-voltage load-shedding scheme that is not applicable to this standard is one in which the tripping action was intended to prevent low distribution voltage to a specific Load from a Transmission system that was intact except for the line that was out of service, as opposed to preventing a Cascading outage or Transmission system collapse.

It had been correctly noted that the devices needed for PRC-011 are the very same types of devices needed in PRC-005.

Thus, a standard written for Protection Systems of the BES can easily make the needed requirements for Protection Systems, and replace some other standards at the same time.

2.3.1 Frequently Asked Questions:

What exactly is the BES, or Bulk Electric System?
BES is the abbreviation for Bulk Electric System. BES is a term in the Glossary of Terms used in Reliability Standards, and is not being modified within this draft standard.
NERC's approved definition of Bulk Electric System is:

As defined by the Regional Reliability Organization, the electrical generation resources, transmission lines, Interconnections with neighboring Systems, and associated equipment, generally operated at voltages of 100 kV or higher. Radial transmission Facilities serving only Load with one transmission source are generally not included in this definition.

The BES definition is presently undergoing the process of revision.

Each regional entity implements a definition of the Bulk Electric System that is based on this NERC definition; in some cases, supplemented by additional criteria. These regional definitions have been documented and provided to FERC as part of a *June 14, 2007 Informational Filing*.

Why is Distribution Provider included within the Applicable Entities and as a responsible entity within several of the requirements? Wouldn't anyone having relevant Facilities be a Transmission Owner?

Depending on the station configuration of a particular substation, there may be Protection System equipment installed at a non-transmission voltage level (Distribution Provider equipment) that is wholly or partially installed to protect the BES. PRC-005-X applies to this equipment. An example is underfrequency load-shedding, which is frequently applied well down into the distribution system to meet PRC-007-0.

We have an under voltage load-shedding (UVLS) system in place that prevents one of our distribution substations from supplying extremely low voltage in the case of a specific transmission line outage. The transmission line is part of the BES. Does this mean that our UVLS system falls within this standard?

The situation, as stated, indicates that the tripping action was intended to prevent low distribution voltage to a specific Load from a Transmission System that was intact, except for the line that was out of service, as opposed to preventing Cascading outage or Transmission System Collapse.

This standard is not applicable to this UVLS.

We have a UFLS or UVLS scheme that sheds the necessary Load through distribution-side circuit breakers and circuit reclosers. Do the trip-test requirements for circuit breakers apply to our situation?

No. Distributed tripping schemes would have to exhibit multiple failures to trip before they would prove to be significant, as opposed to a single failure to trip of, for example, a transmission Protection System bus differential lock-out relay. While many failures of these distribution breakers could add up to be significant, it is also believed that distribution breakers are operated often on just Fault clearing duty; and, therefore, the distribution circuit breakers are operated at least as frequently as any requirements that might have appeared in this standard.

We have a UFLS scheme that, in some locales, sheds the necessary Load through non-BES circuit breakers and, occasionally, even circuit switchers. Do the trip-test requirements for circuit breakers apply to our situation?

If your "non-BES circuit breaker" has been brought into this standard by the inclusion of UFLS requirements, and otherwise would not have been brought into this standard, then the answer is that there are no trip-test requirements. For these devices that are otherwise non-BES assets, these tripping schemes would have to exhibit multiple failures to trip before they would prove to be as significant as, for example, a single failure to trip of a transmission Protection System bus differential lock-out relay.

How does the "Facilities" section of "Applicability" track with the standards that will be retired once PRC-005-2 becomes effective?

In establishing PRC-005-2, the drafting team combined legacy standards PRC-005-1b, PRC-008-0, PRC-011-0, and PRC-017-0. The merger of the subject matter of these standards is reflected in Applicability 4.2.

The intent of the drafting team is that the legacy standards be reflected in PRC-005-2 as follows:

- Applicability of PRC-005-1b for Protection Systems relating to non-generator elements of the BES is addressed in 4.2.1;
- Applicability of PRC-008-0 for underfrequency load shedding systems is addressed in 4.2.2;
- Applicability of PRC-011-0 for undervoltage load shedding relays is addressed in 4.2.3;
- Applicability of PRC-017-0 for Special Protection Systems is addressed in 4.2.4;
- Applicability of PRC-005-1b for Protection Systems for BES generators is addressed in 4.2.5.

2.4 Applicable Relays

The NERC Glossary definition has a Protection System including relays, dc supply, current and voltage sensing devices, dc control circuitry and associated communications circuits. The relays to which this standard applies are those protective relays that respond to electrical quantities and provide a trip output to trip coils, dc control circuitry or associated communications equipment. This definition extends to IEEE Device No. 86 (lockout relay) and IEEE Device No. 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.

Relays that respond to non-electrical inputs or impulses (such as, but not limited to, vibration, seismic, thermal or gas accumulation) are not included.

Automatic Reclosing is addressed in PRC-005-3 by explicitly addressing them outside the definition of Protection System. The specific locations for applicable Automatic Reclosing are addressed in Applicability Section 4.2.6~~7~~.

Sudden Pressure Relaying is addressed in PRC-005-X by explicitly addressing them outside the definition of Protection System. The specific locations for applicable Sudden Pressure Relaying are addressed in Applicability Section 4.2.1, 4.2.5.2, 4.2.5.3 and 4.2.5.4~~6~~.

2.4.1 Frequently Asked Questions:

Are power circuit reclosers, reclosing relays, closing circuits and auto-restoration schemes covered in this Standard?

Yes. Automatic Reclosing includes reclosing relays and the associated dc control circuitry. Section 4.2.6 of the Applicability specifically limits the applicable reclosing relays to:

4.2.6 Automatic Reclosing

4.2.6.1 Automatic Reclosing applied on the terminals of Elements connected to the BES bus located at generating plant substations where the total installed gross generating plant capacity is greater than the gross capacity of the largest BES generating unit within the Balancing Authority Area or, if a member of a Reserve Sharing Group, the largest generating unit within the Reserve Sharing Group. ~~-~~

4.2.6.2 Automatic Reclosing applied on the terminals of all BES Elements at substations one bus away from generating plants specified in Section 4.2.6.1 when the substation is less than 10 circuit-miles from the generating plant substation.

4.2.6.3 Automatic Reclosing applied as an integral part of a SPS specified in Section 4.2.4.

Further, Footnote 1 to Applicability Section 4.2.6 establishes that Automatic Reclosing addressed in 4.2.6.1 and 4.2.6.2 may be excluded if the equipment owner can demonstrate that a close-in three-phase fault present for twice the normal clearing time (capturing a minimum trip-close-trip time delay) does not result in a total loss of gross generation in the Interconnection exceeding the gross capacity of the largest relevant BES generating unit ~~within the Balancing Authority Area~~ where the Automatic Reclosing is applied.

Additionally, Footnote 2 to Applicability Section 4.2.6.1 advises that the entity's PSMP needs to remain current regarding the applicability of Automatic Reclosing Components relative to the largest generating unit within the Balancing Authority Area or Reserve Sharing Group.

The Applicability as detailed above was recommended by the NERC System Analysis and Modeling Subcommittee (SAMS) after a lengthy review of the use of reclosing within the BES. SAMS concluded that automatic reclosing is largely implemented throughout the BES as an operating convenience, and that automatic reclosing mal-performance affects BES reliability only when the reclosing is part of a Special Protection System, or when premature autoreclosing has the potential to cause generating unit or plant instability. A technical report, "Considerations for Maintenance and Testing of Autoreclosing Schemes — November 2012", is referenced in PRC-005-3 and provides a more detailed discussion of these concerns.

Why did the standard drafting team not include IEEE device numbers to describe Automatic Reclosing Relays?

The drafting team elected not to include IEEE device numbers to describe Automatic Reclosing because Automatic Reclosing component type could be a stand-alone electromechanical relay; or could be the 79 function within a microprocessor based multi-function relay(11).

Is a sync-check (25) relay included in the Automatic Reclosing Control Circuitry?

Where sync-check relays are included in an Automatic Reclosing scheme that is part of an SPS, the sync-check would be included in the control circuitry (Table 4-2(b)). Where sync-check relays are included in an Automatic Reclosing scheme that is not part of an SPS, the sync-check would not be included in the control circuitry (Table 4-2(a)).

The SDT asserts that a sync-check (25) relay does not initiate closing but rather enables or disables closing and is not considered a part of the actual Automatic Reclosing control circuitry when not part of an SPS.

How do I interpret Applicability Section 4.2.6 to determine applicability in the following examples:

At my generating plant substation, I have a total of 800 MW connected to one voltage level and 200 MW connected to another voltage level. How do I determine my gross capacity? Where do I consider Automatic Reclosing to be applicable?

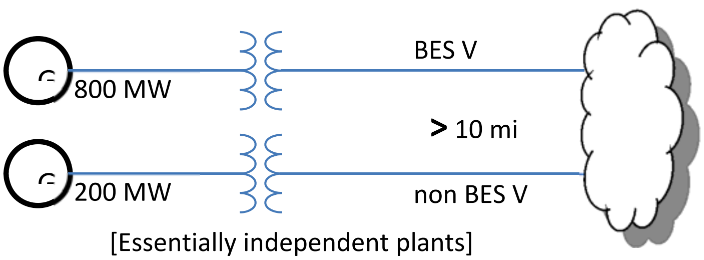
Scenario number 1:

The 800 MW of generation is connected to a BES voltage level bus, the 200 MW ~~unit~~

is connected to a non-BES voltage level bus, and there is no connection between the two buses locally or within 10 circuit miles from the generating plant substation. The largest single unit in the BA area is 750 MW.

In this case, the total installed gross generating capacity would be 800 MW. The two units are essentially independent plants.

The BES voltage level bus is considered to be the bus to which the 800 MW of generation is connected. Any BES Automatic Reclosing at this location, as well as other locations within 10 circuit miles, is considered to be applicable because 800 MW exceeds the largest single unit in the BA area.



[Essentially independent plants]

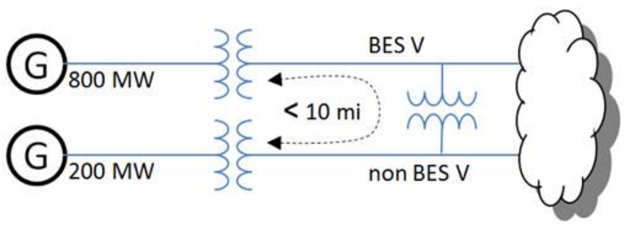
<u>**Gross Capacity**</u>	<u>**Automatic Reclosing in scope**</u>
800 MW	BES V

Scenario number 2:

The 800 MW of generation is connected to a BES voltage level bus, the 200 MW unit is connected to a non-BES voltage level bus, and there is a connection between the two buses locally or within 10 circuit miles from the generating plant substation. The largest single unit in the BA area is 750 MW.

In this case, reclosing into a fault on the BES system could impact the stability of the non-BES-connected generating units. Therefore, the total installed gross generating capacity would be 1000 MW.

The BES voltage level bus is considered to be the bus to which the 800 MW of generation is connected. Any BES Automatic Reclosing at this location, as well as other locations within 10 circuit miles, is considered to be applicable because total of 1000 MW exceeds the largest single unit in the BA area. However, the Automatic Reclosing on the non-BES voltage level bus is not applicable.



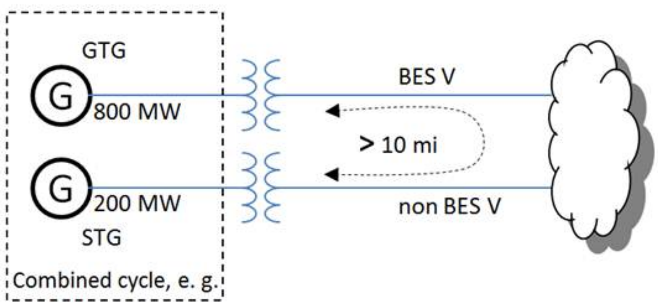
Gross Capacity	**Automatic Reclosing in scope**
1000 MW	BES V

Scenario number 3:

The 800 MW of generation is connected to a BES voltage level bus, the 200 MW unit is connected to a non-BES voltage level bus, and there is no connection between the two buses locally or within 10 circuit miles from the generating plant substation but the generating units connected at the BES voltage level do not operate independently of the units connected at the non BES voltage level (e.g., a combined cycle facility where 800 MW of combustion turbines are connected at a BES voltage level whose exhaust is used to power a 200 MW steam unit connected to a non BES voltage level. The largest single unit in the BA area is 750 MW.

In this case, the total installed gross generating capacity would be 1000 MW. Therefore, reclosing into a fault on the BES voltage level would result in a loss of the 800 MW combustion turbines and subsequently result in the loss of the 200 MW steam unit because of the loss of the heat source to its boiler.

The BES voltage level bus is considered to be the bus to which the 800 MW of generation is connected. Any BES Automatic Reclosing at this location, as well as other locations within 10 circuit miles, is considered to be applicable because total of 1000 MW exceeds the largest single unit in the BA area. However, the Automatic Reclosing on the non-BES voltage level bus is not applicable.



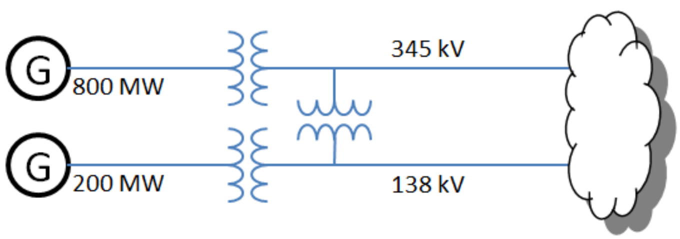
<u>**Gross Capacity**</u>	<u>**Automatic Reclosing in scope**</u>
1000 MW	BES V

Scenario 4

The 800 MW of generation is connected at 345 kV and the 200 MW is connected at 138 kV with an autotransformer at the generating plant substation connecting the two voltage levels. The largest single unit in the BA area is 900 MW.

In this case, the total installed gross generating capacity would be 1000 MW and section 4.2.6.1 would be applicable to both the 345 kV Automatic Reclosing Components and the 138 kV Automatic Reclosing Components, since the total capacity of 1000 MW is larger than the largest single unit in the BA area.

However, if the 345 kV and the 138 kV systems can be shown to be uncoupled such that the 138 kV reclosing relays will not affect the stability of the 345 kV generating units then the 138 kV Automatic Reclosing Components need not be included per section 4.2.6.1.



Gross Capacity	Automatic Reclosing in scope
1000 MW	BOTH*

* The study detailed in Footnote 1 of the draft standard may eliminate the 138 kV Automatic Reclosing Components and/or the 345 kV Automatic Reclosing Components

Why does 4.2.6.2 specify “10 circuit miles”?

As noted in “Considerations for Maintenance and Testing of Autoreclosing Schemes — November 2012”, transmission line impedance on the order of one mile away typically provides adequate impedance to prevent generating unit instability and a 10 mile threshold provides sufficient margin.

Should I use MVA or MW when determining the installed gross generating plant capacity?

Be consistent with the rating used by the Balancing Authority for the largest BES generating unit within their area.

What value should we use for generating plant capacity in 4.2.6.1?

Use the value reported to the Balance Authority for generating plant capacity for planning and modeling purposes. This can be nameplate or other values based on generating plant limitations such as boiler or turbine ratings.

What is considered to be “one bus away” from the generation?

The BES voltage level bus is considered to be the generating plant substation bus to which the generator step-up transformer is connected. “One bus away” is the next bus, connected by either a transmission line or transformer.

I use my protective relays only as sources of metered quantities and breaker status for SCADA and EMS through a substation distributed RTU or data concentrator to the control center. What are the maintenance requirements for the relays?

This standard addresses Protection Systems that are installed for the purpose of detecting Faults on BES Elements (lines, buses, transformers, etc.). Protective relays, providing only the functions mentioned in the question, are not included.

Are Reverse Power Relays installed on the low-voltage side of distribution banks considered to be components of “Protection Systems that are installed for the purpose of detecting Faults on BES Elements (lines, buses, transformers, etc.)”?

Reverse power relays are often installed to detect situations where the transmission source becomes de-energized and the distribution bank remains energized from a source on the low-voltage side of the transformer and the settings are calculated based on the charging current of the transformer from the low-voltage side. Although these relays may operate as a result of a fault on a BES element, they are not ‘installed for the purpose of detecting’ these faults.

Why is the maintenance of Sudden Pressure Relaying being addressed in PRC-005-X?

Proper performance of Sudden Pressure Relaying supports the reliability of the BES because fault pressure relays can detect rapid changes in gas pressure, oil pressure, or oil flow that are indicative of faults within liquid-filled, wire-wound equipment such as turn-to-turn faults which may be undetected by Protection Systems. Additionally, Sudden Pressure

Relaying can quickly detect faults and operate to limit damage to liquid-filled, wire-wound equipment.

What type of devices are classified as fault pressure relay?

There are three main types of fault pressure relays; rapid gas pressure rise, rapid oil pressure rise, and rapid oil flow devices.

Rapid gas pressure devices monitor the pressure in the space above the oil (or other liquid), and initiate tripping action for a rapid rise in gas pressure resulting from the rapid expansion of the liquid caused by a fault. The sensor is located in the gas space.

Rapid oil pressure devices monitor the pressure in the oil (or other liquid), and initiate tripping action for a rapid pressure rise caused by a fault. The sensor is located in the liquid.

Rapid oil flow devices ("Buchholz") monitor the liquid flow between a transformer/reactor and its conservator. Normal liquid flow occurs continuously with ambient temperature changes and with internal heating from loading and does not operate the rapid oil flow device. However, when an internal arc happens a sudden expansion of liquid can be monitored as rapid liquid flow from the transformer into the conservator resulting in actuation of the rapid oil flow device.

Are sudden pressure relays that only initiate an alarm included in the scope of PRC-005-X?

No, the definition of Sudden Pressure Relaying specifies only those that trip an interrupting device(s) to isolate the equipment it is monitoring.

Is Sudden Pressure Relaying installed on distribution transformers included in PRC-005-X?

No, Applicability 4.2.1, 4.2.5.2, 4.2.5.3, 4.2.5.4~~6.1~~, explicitly describe what Sudden Pressure Relaying is included within the standard.

Are non-electrical sensing devices (other than fault pressure relays) such as low oil level or high winding temperatures included in PRC-005-X?

No, based on the SPCS technical document, "Sudden Pressure Relays and Other Devices that Respond to Non-Electrical Quantities – December 2013~~,~~" the only applicable non-electrical sensing devices are ~~fault pressure relays~~Sudden Pressure Relays.

How do I verify the pressure or flow sensing mechanism is operable?

Maintenance activities for the fault pressure relay associated with Sudden Pressure Relaying in PRC-005-X are intended to verify that the pressure and/or flow sensing mechanism are functioning correctly. Beyond this, PRC-005-X requires no calibration (adjusting the operating threshold or measurement accuracy of a measuring element to meet the intended performance requirement) or testing (applying signals to a component to observe functional performance or output behavior, or to diagnose problems) activities. For example, some designs of flow sensing mechanisms allow the operation of a test switch to actuate the limit switch of the flow sensing mechanism. Operation of this test switch and verification of the flow sensing mechanism would meet the requirements of the maintenance activity. Another example involves a gas pressure sensing mechanism which is isolated by a test plug. Removal of the plug and verification of the bellows mechanism would meet the requirements of the maintenance activity.

Why the 6-year maximum maintenance interval for fault pressure relays?

The SDT established the six-year maintenance interval for fault pressure relays (see Table 5, PRC-005-X) based on the recommendation of the System Protection and Control Subcommittee (SPCS). The technical experts of the SPCS were tasked with developing the technical documents to:

i. Describe the devices and functions (to include sudden pressure relays which trip for fault conditions) that should address FERC's concern; and

ii. Propose minimum maintenance activities for such devices and maximum maintenance intervals, including the technical basis for each.

Excerpt from the SPCS technical report: "In order to determine present industry practices related to sudden pressure relay maintenance, the SPCS conducted a survey of Transmission Owners and Generator Owners in all eight Regions requesting information related to their maintenance practices. The SPCS received responses from 75 Transmission Owners and 109 Generator Owners. Note that, for the purpose of the survey, sudden pressure relays included the following: the "sudden pressure relay" (SPR) originally manufactured by Westinghouse, the "rapid pressure rise relay" (RPR) manufactured by Qualitrol, and a variety of Buchholz relays.

Table 2 provides a summary of the results of the responses:

Table 2: Sudden Pressure Relay Maintenance Practices – Survey Results		
-	**Transmission Owner**	**Generator Owner**
Number of responding owners that trip with Sudden Pressure Relays:	67	84
Percentage of responding owners who trip that have a Maintenance Program:	75%	78%
Percentage of maintenance programs that include testing the pressure actuator:	81%	77%
Average Maintenance interval reported:	5.9 years	4.9 years

Additionally, in order to validate the information noted above, the SPCS contacted the following entities for their feedback: the IEEE Power System Relaying Committee, the IEEE Transformer Committee, the Doble Transformer Committee, the NATF System Protection Practices Group, and the EPRI Generator Owner/Operator Technical Focus Group. All of these organizations indicated the results of the SPCS survey are consistent with their respective experiences.

The SPCS discussed the potential difference between the recommended intervals for fault pressure relaying and intervals for transformer maintenance. The SPCS developed the recommended intervals for fault pressure relaying by comparing fault pressure relaying to Protection System Components with similar physical attributes. The SPCS recognized that these intervals may be shorter than some existing or future transformer maintenance intervals, but believed it to be more important to base intervals for fault pressure relaying on similar Protection System Components than transformer maintenance intervals.

The maintenance interval for fault pressure relays can be extended by utilizing performance-based maintenance thereby allowing entities that have maintenance intervals for transformers in excess of six years, to align them.

The standard specifically mentions auxiliary and lock-out relays. What is an auxiliary tripping relay?

An auxiliary relay, IEEE Device No. 94, is described in IEEE Standard C37.2-2008 as: "A device that functions to trip a circuit breaker, contactor, or equipment; to permit immediate tripping by other devices; or to prevent immediate reclosing of a circuit interrupter if it should open automatically, even though its closing circuit is maintained closed."

What is a lock-out relay?

A lock-out relay, IEEE Device No. 86, is described in IEEE Standard C37.2 as: "A device that trips and maintains the associated equipment or devices inoperative until it is reset by an operator, either locally or remotely."

3. Protection System and Automatic Reclosing Product Generations

The likelihood of failure and the ability to observe the operational state of a critical Protection System and Automatic Reclosing both depend on the technological generation of the relays, as well as how long they have been in service. Unlike many other transmission asset groups, protection and control systems have seen dramatic technological changes spanning several generations. During the past 20 years, major functional advances are primarily due to the introduction of microprocessor technology for power system devices, such as primary measuring relays, monitoring devices, control Systems, and telecommunications equipment.

Modern microprocessor-based relays have six significant traits that impact a maintenance strategy:

- Self-monitoring capability - the processors can check themselves, peripheral circuits, and some connected substation inputs and outputs, such as trip coil continuity. Most relay users are aware that these relays have self-monitoring, but are not focusing on exactly what internal functions are actually being monitored. As explained further below, every element critical to the Protection System must be monitored, or else verified periodically.

- Ability to capture Fault records showing how the Protection System responded to a Fault in its zone of protection, or to a nearby Fault for which it is required not to operate.
- Ability to meter currents and voltages, as well as status of connected circuit breakers, continuously during non-Fault times. The relays can compute values, such as MW and MVAR line flows, that are sometimes used for operational purposes, such as SCADA.
- Data communications via ports that provide remote access to all of the results of Protection System monitoring, recording and measurement.
- Ability to trip or close circuit breakers and switches through the Protection System outputs, on command from remote data communications messages, or from relay front panel button requests.
- Construction from electronic components, some of which have shorter technical life or service life than electromechanical components of prior Protection System generations.

There have been significant advances in the technology behind the other components of Protection Systems. Microprocessors are now a part of battery chargers, associated communications equipment, voltage and current-measuring devices, and even the control circuitry (in the form of software-latches replacing lock-out relays, etc.).

Any Protection System component can have self-monitoring and alarming capability, not just relays. Because of this technology, extended time intervals can find their way into all components of the Protection System.

This standard also recognizes the distinct advantage of using advanced technology to justifiably defer or even eliminate traditional maintenance. Just as a hand-held calculator does not require routine testing and calibration, neither does a calculation buried in a microprocessor-based device that results in a “lock-out.” Thus, the software-latch 86 that replaces an electro-mechanical 86 does not require routine trip testing. Any trip circuitry associated with the “soft 86” would still need applicable verification activities performed, but the actual “86” does not have to be “electrically operated” or even toggled.

4. Definitions

Protection System Maintenance Program (PSMP) — An ongoing program by which Protection System, Automatic Reclosing and Sudden Pressure Relaying Components are kept in working order and proper operation of malfunctioning Components is restored. A maintenance program for a specific Component includes one or more of the following activities:

- Verify — Determine that the Component is functioning correctly.
- Monitor — Observe the routine in-service operation of the Component.
- Test — Apply signals to a Component to observe functional performance or output behavior, or to diagnose problems.
- Inspect — Detect visible signs of Component failure, reduced performance and degradation.
- Calibrate — Adjust the operating threshold or measurement accuracy of a measuring element to meet the intended performance requirement.

Automatic Reclosing – Includes the following Components:

- Reclosing relay
- Control circuitry associated with the reclosing relay.

Sudden Pressure Relaying – A system that trips an interrupting device(s) to isolate the equipment it is monitoring and includes the following Components:

- Fault pressure relay – a mechanical relay or device that detects~~ing~~ rapid changes in gas pressure, oil pressure, or oil flow that are indicative of faults within liquid-filled, wire-wound equipment
- Control circuitry associated with a fault pressure relay

Unresolved Maintenance Issue – A deficiency identified during a maintenance activity that causes the component to not meet the intended performance, cannot be corrected during the maintenance interval, and requires follow-up corrective action.

Segment – Components of a consistent design standard, or a particular model or type from a single manufacturer that typically share other common elements. Consistent performance is expected across the entire population of a Segment. A Segment must contain at least sixty (60) individual Components.

Component Type –

- Any one of the five specific elements of a Protection System.
- Any one of the two specific elements of Automatic Reclosing.
- Any one of the two specific elements of Sudden Pressure Relaying.

Component – Any individual discrete piece of equipment included in a Protection System, Automatic Reclosing, or Sudden Pressure Relaying.

Countable Event – A failure of a Component requiring repair or replacement, any condition discovered during the maintenance activities in Tables 1-1 through 1-5, Table 3, Tables 4-1 through 4-2, and Table 5, which requires corrective action or a Protection System Misoperation attributed to hardware failure or calibration failure. Misoperations due to product design errors, software errors, relay settings different from specified settings, Protection System Component, Automatic Reclosing or Sudden Pressure Relaying configuration or application errors are not included in Countable Events.

4.1 Frequently Asked Questions:

Why does PRC-005-X not specifically require maintenance and testing procedures, as reflected in the previous standard, PRC-005-1?

PRC-005-1 does not require detailed maintenance and testing procedures, but instead requires summaries of such procedures, and is not clear on what is actually required. PRC-005-X requires a documented maintenance program, and is focused on establishing requirements rather than prescribing methodology to meet those requirements. Between the activities identified in the Tables 1-1 through 1-5, Table 2, Table 3, and Table 4 (collectively the "Tables"), and the various components of the definition established for a "Protection System Maintenance Program," PRC-005-X establishes the activities and time basis for a Protection System Maintenance Program to a level of detail not previously required.

Please clarify what is meant by "restore" in the definition of maintenance.

The description of "restore" in the definition of a Protection System Maintenance Program addresses corrective activities necessary to assure that the component is returned to working order following the discovery of its failure or malfunction. The Maintenance Activities specified in the Tables do not present any requirements related to Restoration; R5 of the standard does require that the entity "shall demonstrate efforts to correct any identified Unresolved Maintenance Issues." Some examples of restoration (or correction of Unresolved Maintenance Issues) include, but are not limited to, replacement of capacitors in distance relays to bring them to working order; replacement of relays, or other Protection System components, to bring the Protection System to working order; upgrade of electromechanical or solid-state protective relays to microprocessor-based relays following the discovery of failed components. Restoration, as used in this context, is not to be confused with restoration rules as used in system operations. Maintenance activity necessarily includes both the detection of problems and the repairs needed to eliminate those problems. This standard does not identify all of the Protection System problems that must be detected and eliminated, rather it is the intent of this standard that an entity determines the necessary working order for their various devices, and keeps them in working order. If an equipment item is repaired or replaced, then the entity can restart the maintenance-time-interval-clock, if desired; however, the replacement of equipment does not remove any documentation requirements that would have been required to verify compliance with time-interval requirements. In other words, do not discard maintenance data that goes to verify your work.

The retention of documentation for new and/or replaced equipment is all about proving that the maintenance intervals had been in compliance. For example, a long-range plan of upgrades might lead an entity to ignore required maintenance; retaining the evidence of prior maintenance that existed before any retirements and upgrades proves compliance with the standard.

Please clarify what is meant by "…demonstrate efforts to correct an Unresolved Maintenance Issue…"; why not measure the completion of the corrective action?

Management of completion of the identified Unresolved Maintenance Issue is a complex topic that falls outside of the scope of this standard. There can be any number of supply, process and management problems that make setting repair deadlines impossible. The SDT specifically chose the phrase "demonstrate efforts to correct" (with guidance from NERC Staff) because of the concern that many more complex Unresolved Maintenance Issues might require greater than the remaining maintenance interval to resolve (and yet still be a "closed-end process"). For example, a problem might be identified on a VRLA battery during a six-month check. In instances such as one that requiring battery replacement as part of the long-term resolution, it is highly unlikely that the battery could be replaced in time to meet the six-calendar-month requirement for this maintenance activity. The SDT does not believe entities should be found in violation of a maintenance program requirement because of the inability to complete a remediation program within the original maintenance interval. The SDT does believe corrective actions should be timely, but concludes it would be impossible to postulate all possible remediation projects; and, therefore, impossible to specify bounding time frames for resolution of all possible Unresolved Maintenance Issues, or what documentation might be sufficient to provide proof that effective corrective action is being undertaken.

5. Time-Based Maintenance (TBM) Programs

Time-based maintenance is the process in which Protection System, Automatic Reclosing and Sudden Pressure Relaying Components are maintained or verified according to a time schedule. The scheduled program often calls for technicians to travel to the physical site and perform a functional test on Protection System components. However, some components of a TBM program may be conducted from a remote location - for example, tripping a circuit breaker by communicating a trip command to a microprocessor relay to determine if the entire Protection System tripping chain is able to operate the breaker. Similarly, all Protection System, and Sudden Pressure Relaying Components can have the ability to remotely conduct tests, either on-command or routinely; the running of these tests can extend the time interval between hands-on maintenance activities.

5.1 Maintenance Practices

Maintenance and testing programs often incorporate the following types of maintenance practices:

- TBM – time-based maintenance – externally prescribed maximum maintenance or testing intervals are applied for components or groups of components. The intervals may have been developed from prior experience or manufacturers' recommendations. The TBM verification interval is based on a variety of factors, including experience of the particular asset owner, collective experiences of several asset owners who are members of a country or regional council, etc. The maintenance intervals are fixed and may range in number of months or in years.

  TBM can include review of recent power system events near the particular terminal. Operating records may verify that some portion of the Protection System has operated correctly since the last test occurred. If specific protection scheme components have demonstrated correct performance within specifications, the maintenance test time clock can be reset for those components.

- PBM – Performance-Based Maintenance - intervals are established based on analytical or historical results of TBM failure rates on a statistically significant population of similar components. Some level of TBM is generally followed. Statistical analyses accompanied by adjustments to maintenance intervals are used to justify continued use of PBM-developed extended intervals when test failures or in-service failures occur infrequently.

- CBM – condition-based maintenance – continuously or frequently reported results from non-disruptive self-monitoring of components demonstrate operational status as those components remain in service. Whatever is verified by CBM does not require manual testing, but taking advantage of this requires precise technical focus on exactly what parts are included as part of the self-diagnostics. While the term "Condition-Based-Maintenance" (CBM) is no longer used within the standard itself, it is important to note that the concepts of CBM are a part of the standard (in the form of extended time intervals through status-monitoring). These extended time intervals are only allowed (in the absence of PBM) if the condition of the device is monitored (CBM). As a consequence of the "monitored-basis-time-intervals" existing within the standard, the explanatory discussions within this Supplementary Reference concerned with CBM will remain in this reference and are discussed as CBM.

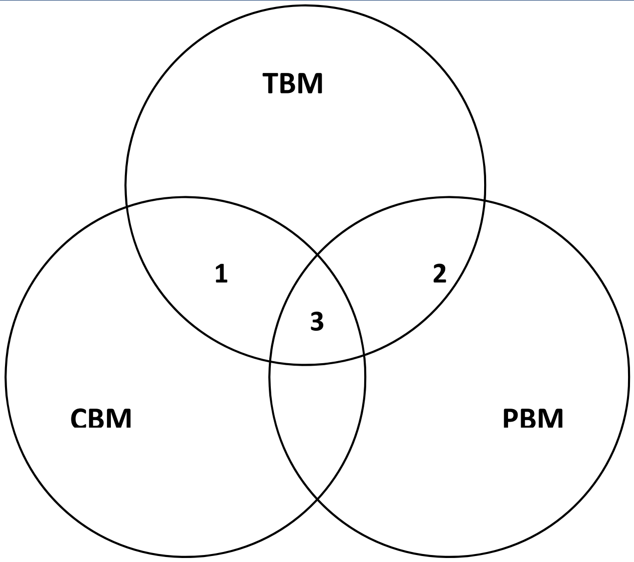
Microprocessor-based Protection System or Automatic Reclosing Components that perform continuous self-monitoring verify correct operation of most components within the device. Self-monitoring capabilities may include battery continuity, float voltages, unintentional grounds, the ac signal inputs to a relay, analog measuring circuits, processors and memory for measurement, protection, and data communications, trip circuit monitoring, and protection or data communications signals (and many, many more measurements). For those conditions, failure of a self-monitoring routine generates an alarm and may inhibit operation to avoid false trips. When internal components, such as critical output relay contacts, are not equipped with self-monitoring, they can be manually tested. The method of testing may be local or remote, or through inherent performance of the scheme during a system event.

The TBM is the overarching maintenance process of which the other types are subsets. Unlike TBM, PBM intervals are adjusted based on good or bad experiences. The CBM verification intervals can be hours, or even milliseconds between non-disruptive self-monitoring checks within or around components as they remain in service.

TBM, PBM, and CBM can be combined for individual components, or within a complete Protection System. The following diagram illustrates the relationship between various types of maintenance practices described in this section. In the Venn diagram, the overlapping regions show the relationship of TBM with PBM historical information and the inherent continuous monitoring offered through CBM.

This figure shows:

- Region 1: The TBM intervals that are increased based on known reported operational condition of individual components that are monitoring themselves.
- Region 2: The TBM intervals that are adjusted up or down based on results of analysis of maintenance history of statistically significant population of similar products that have been subject to TBM.
- Region 3: Optimal TBM intervals based on regions 1 and 2.



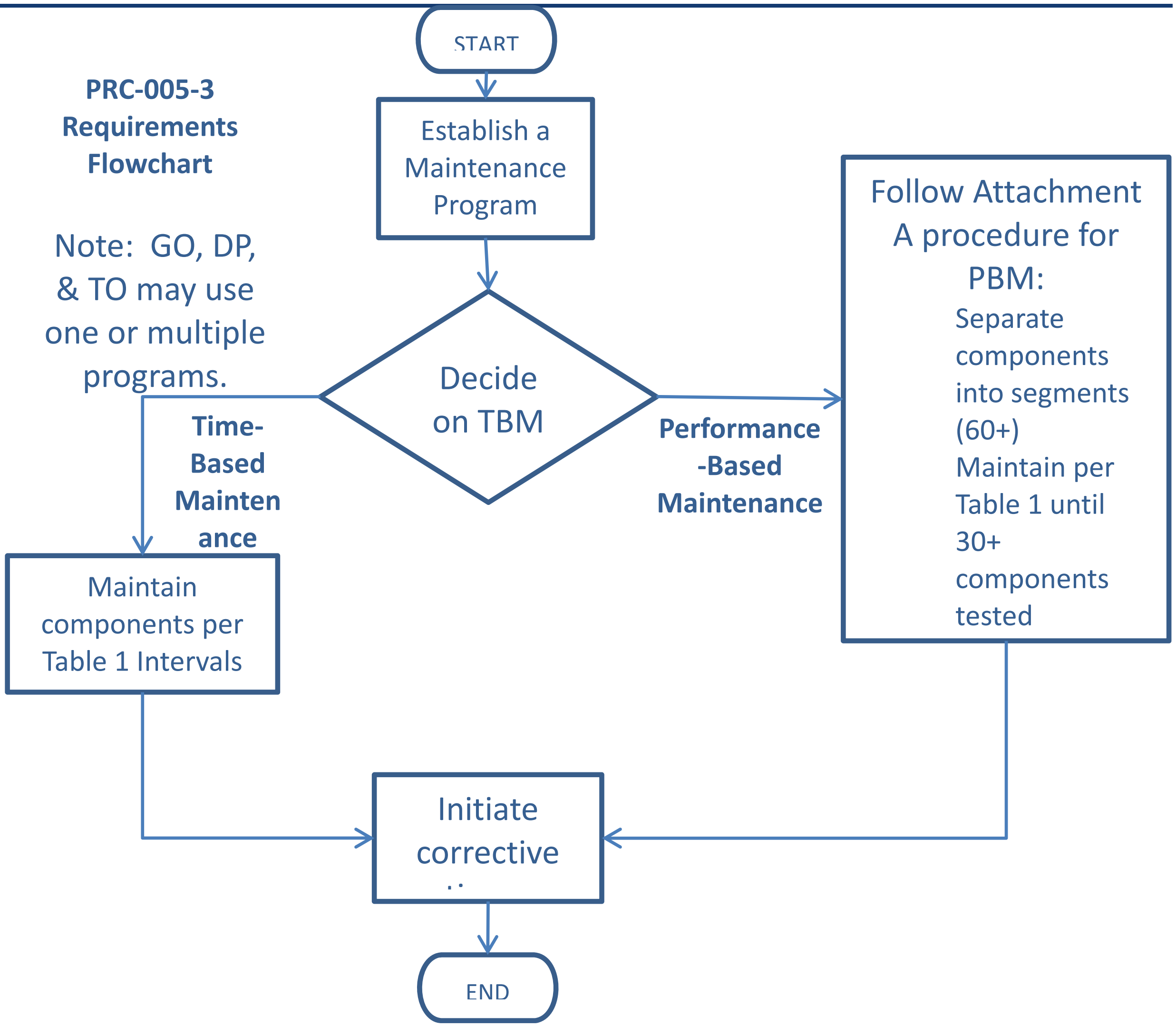
Relationship of time-based maintenance types

5.1.1 Frequently Asked Questions:

The standard seems very complicated, and is difficult to understand. Can it be simplified?

Because the standard is establishing parameters for condition-based Maintenance (R1) and Performance-Based Maintenance (R2), in addition to simple time-based Maintenance, it does appear to be complicated. At its simplest, an entity needs to ONLY perform time-based maintenance according to the unmonitored rows of the Tables. If an entity then wishes to take advantage of monitoring on its Protection System components and its available lengthened time intervals, then it may, as long as the component has the listed monitoring attributes. If an entity wishes to use historical performance of its Protection System components to perform Performance-Based Maintenance, then R2 applies.

Please see the following diagram, which provides a “flow chart” of the standard.



We have an electromechanical (unmonitored) relay that has a trip output to a lockout relay (unmonitored) which trips our transformer off-line by tripping the transformer's high-side and low-side circuit breakers. What testing must be done for this system?

This system is made up of components that are all unmonitored. Assuming a time-based Protection System Maintenance Program schedule (as opposed to a Performance-Based maintenance program), each component must be maintained per the most frequent hands-on activities listed in the Tables.

5.2 Extending Time-Based Maintenance

All maintenance is fundamentally time-based. Default time-based intervals are commonly established to assure proper functioning of each component of the Protection System, when data on the reliability of the components is not available other than observations from time-based maintenance. The following factors may influence the established default intervals:

- If continuous indication of the functional condition of a component is available (from relays or chargers or any self-monitoring device), then the intervals may be extended, or manual testing may be eliminated. This is referred to as condition-based maintenance or CBM. CBM is valid only for precisely the components subject to monitoring. In the case of microprocessor-based relays, self-monitoring may not include automated diagnostics of every component within a microprocessor.

- Previous maintenance history for a group of components of a common type may indicate that the maintenance intervals can be extended, while still achieving the desired level of performance. This is referred to as Performance-Based Maintenance, or PBM. It is also sometimes referred to as reliability-centered maintenance, or RCM; but PBM is used in this document.
- Observed proper operation of a component may be regarded as a maintenance verification of the respective component or element in a microprocessor-based device. For such an observation, the maintenance interval may be reset only to the degree that can be verified by data available on the operation. For example, the trip of an electromechanical relay for a Fault verifies the trip contact and trip path, but only through the relays in series that actually operated; one operation of this relay cannot verify correct calibration.

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. The improper application of test signals may cause failure of a component. For example, in electromechanical overcurrent relays, test currents have been known to destroy convolution springs.

In addition, maintenance usually takes the component out of service, during which time it is not able to perform its function. Cutout switch failures, or failure to restore switch position, commonly lead to protection failures.

5.2.1 Frequently Asked Questions:

If I show the protective device out of service while it is being repaired, then can I add it back as a new protective device when it returns? If not, my relay testing history would show that I was out of compliance for the last maintenance cycle.

The maintenance and testing requirements (R5) (in essence) state "…shall demonstrate efforts to correct any identified Unresolved Maintenance Issues." The type of corrective activity is not stated; however it could include repairs or replacements.

Your documentation requirements will increase, of course, to demonstrate that your device tested bad and had corrective actions initiated. Your regional entity could very well ask for documentation showing status of your corrective actions.

6. Condition-Based Maintenance (CBM) Programs

Condition-based maintenance is the process of gathering and monitoring the information available from modern microprocessor-based relays and other intelligent electronic devices (IEDs) that monitor Protection System or Automatic Reclosing elements. These devices generate monitoring information during normal operation, and the information can be assessed at a convenient location remote from the substation. The information from these relays and IEDs is divided into two basic types:

1. Information can come from background self-monitoring processes, programmed by the manufacturer, or by the user in device logic settings. The results are presented by alarm contacts or points, front panel indications, and by data communications messages.
2. Information can come from event logs, captured files, and/or oscillographic records for Faults and Disturbances, metered values, and binary input status reports. Some of these are available on the device front panel display, but may be available via data communications ports. Large files of Fault information can only be retrieved via data communications. These results comprise a mass of data that must be further analyzed for evidence of the operational condition of the Protection System.

Using these two types of information, the user can develop an effective maintenance program carried out mostly from a central location remote from the substation. This approach offers the following advantages:

Non-invasive Maintenance: The system is kept in its normal operating state, without human intervention for checking. This reduces risk of damage, or risk of leaving the system in an inoperable state after a manual test. Experience has shown that keeping human hands away from equipment known to be working correctly enhances reliability.

Virtually Continuous Monitoring: CBM will report many hardware failure problems for repair within seconds or minutes of when they happen. This reduces the percentage of problems that are discovered through incorrect relaying performance. By contrast, a hardware failure discovered by TBM may have been there for much of the time interval between tests, and there is a good chance that some devices will show health problems by incorrect operation before being caught in the next test round. The frequent or continuous nature of CBM makes the effective verification interval far shorter than any required TBM maximum interval. To use the extended time intervals available through Condition Based Maintenance, simply look for the rows in the Tables that refer to monitored items.

6.1 Frequently Asked Questions:

My microprocessor relays and dc circuit alarms are contained on relay panels in a 24-hour attended control room. Does this qualify as an extended time interval condition-based (monitored) system?

Yes, provided the station attendant (plant operator, etc.) monitors the alarms and other indications (comparable to the monitoring attributes) and reports them within the given time limits that are stated in the criteria of the Tables.

When documenting the basis for inclusion of components into the appropriate levels of monitoring, as per Requirement R1 (Part 1.4) of the standard, is it necessary to provide this documentation about the device by listing of every component and the specific monitoring attributes of each device?

No. While maintaining this documentation on the device level would certainly be permissible, it is not necessary. Global statements can be made to document appropriate levels of monitoring for the entire population of a component type or portion thereof.

For example, it would be permissible to document the conclusion that all BES substation dc supply battery chargers are monitored by stating the following within the program description:

> "All substation dc supply battery chargers are considered monitored and subject to the rows for monitored equipment of Table 1-4 requirements, as all substation dc supply battery chargers are equipped with dc voltage alarms and ground detection alarms that are sent to the manned control center."

Similarly, it would be acceptable to use a combination of a global statement and a device-level list of exclusions. Example:

> "Except as noted below, all substation dc supply battery chargers are considered monitored and subject to the rows for monitored equipment of Table 1-4 requirements, as all substation dc supply battery chargers are equipped with dc voltage alarms and ground detection alarms that are sent to the manned control center. The dc supply battery chargers of Substation X, Substation Y, and Substation Z are considered unmonitored and subject to the rows for unmonitored equipment in Table 1-4 requirements, as they are not equipped with ground detection capability."

Regardless whether this documentation is provided by device listing of monitoring attributes, by global statements of the monitoring attributes of an entire population of component types, or by some combination of these methods, it should be noted that auditors may request supporting drawings or other documentation necessary to validate the inclusion of the device(s) within the appropriate level of monitoring. This supporting background information need not be maintained within the program document structure, but should be retrievable if requested by an auditor.

7. Time-Based Versus Condition-Based Maintenance

Time-based and condition-based (or monitored) maintenance programs are both acceptable, if implemented according to technically sound requirements. Practical programs can employ a *combination of time-based and condition-based maintenance.* The standard requirements introduce the concept of optionally using condition monitoring as a documented element of a maintenance program.

The Federal Energy Regulatory Commission (FERC), in its Order Number 693 Final Rule, dated March 16, 2007 (18 CFR Part 40, Docket No. RM06-16-000) on Mandatory Reliability Standards for the Bulk-Power System, directed NERC to submit a modification to PRC-005-1b that includes a requirement that maintenance and testing of a Protection System must be carried out within a maximum allowable interval that is appropriate to the type of the Protection System and its impact on the reliability of the Bulk Power System. Accordingly, this Supplementary Reference Paper refers to the specific maximum allowable intervals in PRC-005-X. The defined time limits allow for longer time intervals if the maintained component is monitored.

A key feature of condition-based monitoring is that it effectively reduces the time delay between the moment of a protection failure and time the Protection System or Automatic Reclosing owner knows about it, for the monitored segments of the Protection System. In some cases, the verification is practically continuous - the time interval between verifications is minutes or seconds. Thus, technically sound, condition-based verification, meets the verification requirements of the FERC order even more effectively than the strictly time-based tests of the same system components.

The result is that:

This NERC standard permits utilities to use a technically sound approach and to take advantage of remote monitoring, data analysis, and control capabilities of modern Protection System and Automatic Reclosing Components to reduce the need for periodic site visits and invasive testing of components by on-site technicians. This periodic testing must be conducted within the maximum time intervals specified in the Tables of PRC-005-X.

7.1 Frequently Asked Questions:

What is a Calendar Year?

Calendar Year - January 1 through December 31 of any year. As an example, if an event occurred on June 17, 2009 and is on a “One Calendar Year Interval,” the next event would have to occur on or before December 31, 2010.

Please provide an example of “4 Calendar Months”.

If a maintenance activity is described as being needed every four Calendar Months then it is performed in a (given) month and due again four months later. For example a battery bank is inspected in month number 1 then it is due again before the end of the month number5. And specifically consider that you perform your battery inspection on January 3, 2010 then it must be inspected again before the end of May. Another example could be that a four-month inspection was performed in January is due in May, but if performed in March (instead of May) would still be due four months later therefore the activity is due again July. Basically every "four Calendar Months" means to add four months from the last time the activity was performed.

Please provide an example of the unmonitored versus other levels of monitoring available?

An unmonitored Protection System has no monitoring and alarm circuits on the Protection System components. A Protection System component that has monitoring attributes but no alarm output connected is considered to be unmonitored.

A monitored Protection System or an individual monitored component of a Protection System has monitoring and alarm circuits on the Protection System components. The alarm circuits must alert, within 24 hours, a location wherein corrective action can be initiated. This location might be, but is not limited to, an Operations Center, Dispatch Office, Maintenance Center or even a portable SCADA system.

There can be a combination of monitored and unmonitored Protection Systems within any given scheme, substation or plant; there can also be a combination of monitored and unmonitored components within any given Protection System.

Example #1: A combination of monitored and unmonitored components within a given Protection System might be:

- A microprocessor relay with an internal alarm connected to SCADA to alert 24-hr staffed operations center; it has internal self-diagnosis and alarming. (monitored)
- Instrumentation transformers, with no monitoring, connected as inputs to that relay. (unmonitored)
- A vented Lead-Acid battery with a low voltage alarm for the station dc supply voltage and an unintentional grounds detection alarm connected to SCADA. (monitoring varies)
- A circuit breaker with a trip coil, and the trip circuit is not monitored. (unmonitored)

Given the particular components and conditions, and using Table 1 and Table 2, the particular components have maximum activity intervals of:

<u>Every four calendar months</u>, inspect:

- Electrolyte level (station dc supply voltage and unintentional ground detection is being maintained more frequently by the monitoring system).

<u>Every 18 calendar months</u>, verify/inspect the following:

- Battery bank ohmic values to station battery baseline (if performance tests are not opted)
- Battery charger float voltage
- Battery rack integrity
- Cell condition of all individual battery cells (where visible)
- Battery continuity
- Battery terminal connection resistance

- Battery cell-to-cell resistance (where available to measure)

Every six calendar years, perform/verify the following:

- Battery performance test (if internal ohmic tests or other measurements indicative of battery performance are not opted)
- Verify that each trip coil is able to operate the circuit breaker, interrupting device, or mitigating device
- For electromechanical lock-out relays, electrical operation of electromechanical trip

Every 12 calendar years, verify the following:

- Microprocessor relay settings are as specified
- Operation of the microprocessor's relay inputs and outputs that are essential to proper functioning of the Protection System
- Acceptable measurement of power System input values seen by the microprocessor protective relay
- Verify that current and voltage signal values are provided to the protective relays
- Protection System component monitoring for the battery system signals are conveyed to a location where corrective action can be initiated
- The microprocessor relay alarm signals are conveyed to a location where corrective action can be initiated
- Verify all trip paths in the control circuitry associated with protective functions through the trip coil(s) of the circuit breakers or other interrupting devices
- Auxiliary outputs that are in the trip path shall be maintained as detailed in Table 1-5 of the standard under the 'Unmonitored Control Circuitry Associated with Protective Functions" section'
- Auxiliary outputs not in a trip path (i.e., annunciation or DME input) are not required, by this standard, to be checked

Example #2: A combination of monitored and unmonitored components within a given Protection System might be:

- A microprocessor relay with integral alarm that is not connected to SCADA. (unmonitored)
- Current and voltage signal values, with no monitoring, connected as inputs to that relay. (unmonitored)
- A vented lead-acid battery with a low voltage alarm for the station dc supply voltage and an unintentional grounds detection alarm connected to SCADA. (monitoring varies)
- A circuit breaker with a trip coil, with no circuits monitored. (unmonitored)

Given the particular components and conditions, and using the Table 1 (Maximum Allowable Testing Intervals and Maintenance Activities) and Table 2 (Alarming Paths and Monitoring), the particular components have maximum activity intervals of:

Every four calendar months, inspect:

- Electrolyte level (station dc supply voltage and unintentional ground detection is being maintained more frequently by the monitoring system)

Every 18 calendar months, verify/inspect the following:

- Battery bank trending of ohmic values or other measurements indicative of battery performance to station battery baseline (if performance tests are not opted)
- Battery charger float voltage
- Battery rack integrity
- Cell condition of all individual battery cells (where visible)
- Battery continuity
- Battery terminal connection resistance
- Battery cell-to-cell resistance (where available to measure)

Every six calendar years, verify/perform the following:

- Verify operation of the relay inputs and outputs that are essential to proper functioning of the Protection System
- Verify acceptable measurement of power system input values as seen by the relays
- Verify that each trip coil is able to operate the circuit breaker, interrupting device, or mitigating device
- For electromechanical lock-out relays, electrical operation of electromechanical trip
- Battery performance test (if internal ohmic tests are not opted)

Every 12 calendar years, verify the following:

- Current and voltage signal values are provided to the protective relays
- Protection System component monitoring for the battery system signals are conveyed to a location where corrective action can be initiated
- All trip paths in the control circuitry associated with protective functions through the trip coil(s) of the circuit breakers or other interrupting devices
- Auxiliary outputs that are in the trip path shall be maintained, as detailed in Table 1-5 of the standard under the Unmonitored Control Circuitry Associated with Protective Functions" section
- Auxiliary outputs not in a trip path (i.e., annunciation or DME input) are not required, by this standard, to be checked

Example #3: A combination of monitored and unmonitored components within a given Protection System might be:

- A microprocessor relay with alarm connected to SCADA to alert 24-hr staffed operations center; it has internal self-diagnosis and alarms. (monitored)
- Current and voltage signal values, with monitoring, connected as inputs to that relay (monitored)

- Vented Lead-Acid battery without any alarms connected to SCADA (unmonitored)
- Circuit breaker with a trip coil, with no circuits monitored (unmonitored)

Given the particular components, conditions, and using the Table 1 (Maximum Allowable Testing Intervals and Maintenance Activities) and Table 2 (Alarming Paths and Monitoring), the particular components shall have maximum activity intervals of:

Every four calendar months, verify/inspect the following:

- Station dc supply voltage
- For unintentional grounds
- Electrolyte level

Every 18 calendar months, verify/inspect the following:

- Battery bank trending of ohmic values or other measurements indicative of battery performance to station battery baseline (if performance tests are not opted)
- Battery charger float voltage
- Battery rack integrity
- Battery continuity
- Battery terminal connection resistance
- Battery cell-to-cell resistance (where available to measure)
- Condition of all individual battery cells (where visible)

Every six calendar years, perform/verify the following:

- Battery performance test (if internal ohmic tests or other measurements indicative of battery performance are not opted)
- Verify that each trip coil is able to operate the circuit breaker, interrupting device, or mitigating device
- For electromechanical lock-out relays, electrical operation of electromechanical trip

Every 12 calendar years, verify the following:

- The microprocessor relay alarm signals are conveyed to a location where corrective action can be taken
- Microprocessor relay settings are as specified
- Operation of the microprocessor's relay inputs and outputs that are essential to proper functioning of the Protection System
- Acceptable measurement of power system input values seen by the microprocessor protective relay
- Verify all trip paths in the control circuitry associated with protective functions through the trip coil(s) of the circuit breakers or other interrupting devices

- Auxiliary outputs that are in the trip path shall be maintained, as detailed in Table 1-5 of the standard under the Unmonitored Control Circuitry Associated with Protective Functions section
- Auxiliary outputs not in a trip path (i.e. annunciation or DME input) are not required, by this standard, to be checked

Why do components have different maintenance activities and intervals if they are monitored?

The intent behind different activities and intervals for monitored equipment is to allow less frequent manual intervention when more information is known about the condition of Protection System components. Condition-Based Maintenance is a valuable asset to improve reliability.

Can all components in a Protection System be monitored?

No. For some components in a Protection System, monitoring will not be relevant. For example, a battery will always need some kind of inspection.

We have a 30-year-old oil circuit breaker with a red indicating lamp on the substation relay panel that is illuminated only if there is continuity through the breaker trip coil. There is no SCADA monitor or relay monitor of this trip coil. The line protection relay package that trips this circuit breaker is a microprocessor relay that has an integral alarm relay that will assert on a number of conditions that includes a loss of power to the relay. This alarm contact connects to our SCADA system and alerts our 24-hour operations center of relay trouble when the alarm contact closes. This microprocessor relay trips the circuit breaker only and does not monitor trip coil continuity or other things such as trip current. Are the components monitored or not? How often must I perform maintenance?

The protective relay is monitored and can be maintained every 12 years, or when an Unresolved Maintenance Issue arises. The control circuitry can be maintained every 12 years. The circuit breaker trip coil(s) has to be electrically operated at least once every six years.

What is a mitigating device?

A mitigating device is the device that acts to respond as directed by a Special Protection System. It may be a breaker, valve, distributed control system, or any variety of other devices. This response may include tripping, closing, or other control actions.

8. Maximum Allowable Verification Intervals

The maximum allowable testing intervals and maintenance activities show how CBM with newer device types can reduce the need for many of the tests and site visits that older Protection System components require. As explained below, there are some sections of the Protection System that monitoring or data analysis may not verify. Verifying these sections of the Protection System or Automatic Reclosing requires some persistent TBM activity in the maintenance program. However, some of this TBM can be carried out remotely - for example, exercising a circuit breaker through the relay tripping circuits using the relay remote control capabilities can be used to verify function of one tripping path and proper trip coil operation, if there has been no Fault or routine operation to demonstrate performance of relay tripping circuits.

8.1 Maintenance Tests

Periodic maintenance testing is performed to ensure that the protection and control system is operating correctly after a time period of field installation. These tests may be used to ensure that individual components are still operating within acceptable performance parameters - this type of test is needed for components susceptible to degraded or changing characteristics due to aging and wear. Full system performance tests may be used to confirm that the total Protection System functions from measurement of power system values, to properly identifying Fault characteristics, to the operation of the interrupting devices.

8.1.1 Table of Maximum Allowable Verification Intervals

Table 1 (collectively known as Table 1, individually called out as Tables 1-1 through 1-5), Table 2, Table 3, Table 4-1 through Table 4-2, and Table 5 in the standard specify maximum allowable verification intervals for various generations of Protection Systems, Automatic Reclosing and Sudden Pressure Relaying and categories of equipment that comprise these systems. The right column indicates maintenance activities required for each category.

The types of components are illustrated in Figures 1 and 2 at the end of this paper. Figure 1 shows an example of telecommunications-assisted transmission Protection System comprising substation equipment at each terminal and a telecommunications channel for relaying between the two substations. Figure 2 shows an example of a generation Protection System. The various sub-systems of a Protection System that need to be verified are shown.

Non-distributed UFLS, UVLS, and SPS are additional categories of Table 1 that are not illustrated in these figures. Non-distributed UFLS, UVLS and SPS all use identical equipment as Protection Systems in the performance of their functions; and, therefore, have the same maintenance needs.

Distributed UFLS and UVLS Systems, which use local sensing on the distribution System and trip co-located non-BES interrupting devices, are addressed in Table 3 with reduced maintenance activities.

While it is easy to associate protective relays to multiple levels of monitoring, it is also true that most of the components that can make up a Protection System can also have technological advancements that place them into higher levels of monitoring.

To use the Maintenance Activities and Intervals Tables from PRC-005-X:

- First find the Table associated with your component. The tables are arranged in the order of mention in the definition of Protection System;
    - Table 1-1 is for protective relays,
    - Table 1-2 is for the associated communications systems,
    - Table 1-3 is for current and voltage sensing devices,
    - Table 1-4 is for station dc supply and
    - Table 1-5 is for control circuits.
    - Table 2, is for alarms; this was broken out to simplify the other tables.
    - Table 3 is for components which make-up distributed UFLS and UVLS Systems.
    - Table 4 is for Automatic Reclosing.
    - Table 5 is for Sudden Pressure Relaying.
- Next look within that table for your device and its degree of monitoring. The Tables have different hands-on maintenance activities prescribed depending upon the degree to which you monitor your equipment. Find the maintenance activity that applies to the monitoring level that you have on your piece of equipment.
- This Maintenance activity is the minimum maintenance activity that must be documented.
- If your Performance-Based Maintenance (PBM) plan requires more activities, then you must perform and document to this higher standard. (Note that this does not apply unless you utilize PBM.)
- After the maintenance activity is known, check the maximum maintenance interval; this time is the maximum time allowed between hands-on maintenance activity cycles of this component.
- If your Performance-Based Maintenance plan requires activities more often than the Tables maximum, then you must perform and document those activities to your more stringent standard. (Note that this does not apply unless you utilize PBM.)
- Any given component of a Protection System can be determined to have a degree of monitoring that may be different from another component within that same Protection System. For example, in a given Protection System it is possible for an entity to have a monitored protective relay and an unmonitored associated communications system; this combination would require hands-on maintenance activity on the relay at least once every 12 years and attention paid to the communications system as often as every four months.
- An entity does not have to utilize the extended time intervals made available by this use of condition-based monitoring. An easy choice to make is to simply utilize the unmonitored level of maintenance made available in each of the Tables. While the maintenance activities resulting from this choice would require more maintenance man-

hours, the maintenance requirements may be simpler to document and the resulting maintenance plans may be easier to create.

For each Protection System Component, Table 1 shows maximum allowable testing intervals for the various degrees of monitoring. For each Automatic Reclosing Component, Table 4 shows maximum allowable testing intervals for the various degrees of monitoring. These degrees of monitoring, or levels, range from the legacy unmonitored through a system that is more comprehensively monitored.

It has been noted here that an entity may have a PSMP that is more stringent than PRC-005-X. There may be any number of reasons that an entity chooses a more stringent plan than the minimums prescribed within PRC-005-X, most notable of which is an entity using performance based maintenance methodology. If an entity has a Performance-Based Maintenance program, then that plan must be followed, even if the plan proves to be more stringent than the minimums laid out in the Tables.

8.1.2 Additional Notes for Tables 1-1 through 1-5, Table 3, and Table 4

1. For electromechanical relays, adjustment is required to bring measurement accuracy within the tolerance needed by the asset owner. Microprocessor relays with no remote monitoring of alarm contacts, etc., are unmonitored relays and need to be verified within the Table interval as other unmonitored relays but may be verified as functional by means other than testing by simulated inputs.

2. Microprocessor relays typically are specified by manufacturers as not requiring calibration, but acceptable measurement of power system input values must be verified (verification of the Analog to Digital [A/D] converters) within the Table intervals. The integrity of the digital inputs and outputs that are used as protective functions must be verified within the Table intervals.

3. Any Phasor Measurement Unit (PMU) function whose output is used in a Protection System or SPS (as opposed to a monitoring task) must be verified as a component in a Protection System.

4. In addition to verifying the circuitry that supplies dc to the Protection System, the owner must maintain the station dc supply. The most widespread station dc supply is the station battery and charger. Unlike most Protection System components, physical inspection of station batteries for signs of component failure, reduced performance, and degradation are required to ensure that the station battery is reliable enough to deliver dc power when required. IEEE Standards 450, 1188, and 1106 for vented lead-acid, valve-regulated lead-acid, and nickel-cadmium batteries, respectively (which are the most commonly used substation batteries on the NERC BES) have been developed as an important reference source of maintenance recommendations. The Protection System owner might want to follow the guidelines in the applicable IEEE recommended practices for battery maintenance and testing, especially if the battery in question is used for application requirements in addition to the protection and control demands covered under this standard. However, the Standard Drafting Team has tailored the battery maintenance and testing guidelines in PRC-005-X for the Protection System owner which are application specific for the BES Facilities. While the IEEE

recommendations are all encompassing, PRC-005-X is a more economical approach while addressing the reliability requirements of the BES.

5. Aggregated small entities might distribute the testing of the population of UFLS/UVLS systems, and large entities will usually maintain a portion of these systems in any given year. Additionally, if relatively small quantities of such systems do not perform properly, it will not affect the integrity of the overall program. Thus, these distributed systems have decreased requirements as compared to other Protection Systems.
6. Voltage & current sensing device circuit input connections to the Protection System relays can be verified by (but not limited to) comparison of measured values on live circuits or by using test currents and voltages on equipment out of service for maintenance. The verification process can be automated or manual. The values should be verified to be as expected (phase value and phase relationships are both equally important to verify).
7. "End-to-end test," as used in this Supplementary Reference, is any testing procedure that creates a remote input to the local communications-assisted trip scheme. While this can be interpreted as a GPS-type functional test, it is not limited to testing via GPS. Any remote scheme manipulation that can cause action at the local trip path can be used to functionally-test the dc control circuitry. A documented Real-time trip of any given trip path is acceptable in lieu of a functional trip test. It is possible, with sufficient monitoring, to be able to verify each and every parallel trip path that participated in any given dc control circuit trip. Or another possible solution is that a single trip path from a single monitored relay can be verified to be the trip path that successfully tripped during a Real-time operation. The variations are only limited by the degree of engineering and monitoring that an entity desires to pursue.
8. A/D verification may use relay front panel value displays, or values gathered via data communications. Groupings of other measurements (such as vector summation of bus feeder currents) can be used for comparison if calibration requirements assure acceptable measurement of power system input values.
9. Notes 1-8 attempt to describe some testing activities; they do not represent the only methods to achieve these activities, but rather some possible methods. Technological advances, ingenuity and/or industry accepted techniques can all be used to satisfy maintenance activity requirements; the standard is technology- and method-neutral in most cases.

8.1.3 Frequently Asked Questions:

What is meant by "Verify that settings are as specified" maintenance activity in Table 1-1?

Verification of settings is an activity directed mostly towards microprocessor- based relays. For relay maintenance departments that choose to test microprocessor-based relays in the same manner as electromechanical relays are tested, the testing process sometimes requires that some specific functions be disabled. Later tests might enable the functions previously disabled, but perhaps still other functions or logic statements were then masked out. It is imperative that, when the relay is placed into service, the settings in the relay be the settings that were intended to be in that relay or as the standard states "…settings are as specified."

Many of the microprocessor- based relays available today have software tools which provide this functionality and generate reports for this purpose.

For evidence or documentation of this requirement, a simple recorded acknowledgement that the settings were checked to be as specified is sufficient.

The drafting team was careful not to require "…that the relay settings be correct…" because it was believed that this might then place a burden of proof that the specified settings would result in the correct intended operation of the interrupting device. While that is a noble intention, the measurable proof of such a requirement is immense. The intent is that settings of the component be as specified at the conclusion of maintenance activities, whether those settings may have "drifted" since the prior maintenance or whether changes were made as part of the testing process.

Are electromechanical relays included in the "Verify that settings are as specified" maintenance activity in Table 1-1?

Verification of settings is an activity directed towards the application of protection related functions of microprocessor based relays. Electromechanical relays require calibration verification by voltage and/or current injection; and, thus, the settings are verified during calibration activity. In the example of a time-overcurrent relay, a minor deviation in time dial, versus the settings, may be acceptable, as long as the relay calibration is within accepted tolerances at the injected current amplitudes. A major deviation may require further investigation, as it could indicate a problem with the relay or an incorrect relay style for the application.

The verification of phase current and voltage measurements by comparison to other quantities seems reasonable. How, though, can I verify residual or neutral currents, or 3V0 voltages, by comparison, when my system is closely balanced?

Since these inputs are verified at commissioning, maintenance verification requires ensuring that phase quantities are as expected and that 3IO and 3VO quantities appear equal to or close to 0.

These quantities also may be verified by use of oscillographic records for connected microprocessor relays as recorded during system Disturbances. Such records may compare to similar values recorded at other locations by other microprocessor relays for the same event, or compared to expected values (from short circuit studies) for known Fault locations.

What does this Standard require for testing an auxiliary tripping relay?

Table 1 and Table 3 requires that a trip test must verify that the auxiliary tripping relay(s) and/or lockout relay(s) which are directly in a trip path from the protective relay to the interrupting device trip coil operate(s) electrically. Auxiliary outputs not in a trip path (i.e. annunciation or DME input) are not required, by this standard, to be checked.

Do I have to perform a full end-to-end test of a Special Protection System?

No. All portions of the SPS need to be maintained, and the portions must overlap, but the overall SPS does not need to have a single end-to-end test. In other words it may be tested in piecemeal fashion provided all of the pieces are verified.

What about SPS interfaces between different entities or owners?

As in all of the Protection System requirements, SPS segments can be tested individually, thus minimizing the need to accommodate complex maintenance schedules.

What do I have to do if I am using a phasor measurement unit (PMU) as part of a Protection System or Special Protection System?

Any Phasor Measurement Unit (PMU) function whose output is used in a Protection System or Special Protection System (as opposed to a monitoring task) must be verified as a component in a Protection System.

How do I maintain a Special Protection System or relay sensing for non-distributed UFLS or UVLS Systems?

Since components of the SPS, UFLS and UVLS are the same types of components as those in Protection Systems, then these components should be maintained like similar components used for other Protection System functions. In many cases the devices for SPS, UFLS and UVLS are also used for other protective functions. The same maintenance activities apply with the exception that distributed systems (UFLS and UVLS) have fewer dc supply and control circuitry maintenance activity requirements.

For the testing of the output action, verification may be by breaker tripping, but may be verified in overlapping segments. For example, an SPS that trips a remote circuit breaker might be tested by testing the various parts of the scheme in overlapping segments. Another method is to document the Real-time tripping of an SPS scheme should that occur. Forced trip tests of circuit breakers (etc.) that are a part of distributed UFLS or UVLS schemes are not required.

The established maximum allowable intervals do not align well with the scheduled outages for my power plant. Can I extend the maintenance to the next scheduled outage following the established maximum interval?

No. You must complete your maintenance within the established maximum allowable intervals in order to be compliant. You will need to schedule your maintenance during available outages to complete your maintenance as required, even if it means that you may do protective relay maintenance more frequently than the maximum allowable intervals. The maintenance intervals were selected with typical plant outages, among other things, in mind.

If I am unable to complete the maintenance, as required, due to a major natural disaster (hurricane, earthquake, etc.), how will this affect my compliance with this standard?

The Sanction Guidelines of the North American Electric Reliability Corporation, effective January 15, 2008, provides that the Compliance Monitor will consider extenuating circumstances when considering any sanctions.

What if my observed testing results show a high incidence of out-of-tolerance relays; or, even worse, I am experiencing numerous relay Misoperations due to the relays being out-of-tolerance?

The established maximum time intervals are mandatory only as a not-to-exceed limitation. The establishment of a maximum is measurable. But any entity can choose to test some or all of their Protection System components more frequently (or to express it differently, exceed the minimum requirements of the standard). Particularly if you find that the maximum intervals in the standard do not achieve your expected level of performance, it is understandable that you

would maintain the related equipment more frequently. A high incidence of relay Misoperations is in no one's best interest.

We believe that the four-month interval between inspections is unneccessary. Why can we not perform these inspections twice per year?

The Standard Drafting Team, through the comment process, has discovered that routine monthly inspections are not the norm. To align routine station inspections with other important inspections, the four-month interval was chosen. In lieu of station visits, many activities can be accomplished with automated monitoring and alarming.

Our maintenance plan calls for us to perform routine protective relay tests every 3 years. If we are unable to achieve this schedule, but we are able to complete the procedures in less than the maximum time interval ,then are we in or out of compliance?

According to R3, if you have a time-based maintenance program, then you will be in violation of the standard only if you exceed the maximum maintenance intervals prescribed in the Tables. According to R4, if your device in question is part of a Performance-Based Maintenance program, then you will be in violation of the standard if you fail to meet your PSMP, even if you do not exceed the maximum maintenance intervals prescribed in the Tables. The intervals in the Tables are associated with TBM and CBM; Attachment A is associated with PBM.

Please provide a sample list of devices or systems that must be verified in a generator, generator step-up transformer, generator connected station service or generator connected excitation transformer to meet the requirements of this maintenance standard.

Examples of typical devices and systems that may directly trip the generator, or trip through a lockout relay, may include, but are not necessarily limited to:

- Fault protective functions, including distance functions, voltage-restrained overcurrent functions, or voltage-controlled overcurrent functions
- Loss-of-field relays
- Volts-per-hertz relays
- Negative sequence overcurrent relays
- Over voltage and under voltage protection relays
- Stator-ground relays
- Communications-based Protection Systems such as transfer-trip systems
- Generator differential relays
- Reverse power relays
- Frequency relays
- Out-of-step relays
- Inadvertent energization protection

- Breaker failure protection

For generator step-up, generator-connected station service transformers, or generator connected excitation transformers, operation of any of the following associated protective relays frequently would result in a trip of the generating unit; and, as such, would be included in the program:

- Transformer differential relays
- Neutral overcurrent relay
- Phase overcurrent relays

Relays which trip breakers serving station auxiliary Loads such as pumps, fans, or fuel handling equipment, etc., need not be included in the program, even if the loss of the those Loads could result in a trip of the generating unit. Furthermore, relays which provide protection to secondary unit substation (SUS) or low switchgear transformers and relays protecting other downstream plant electrical distribution system components are not included in the scope of this program, even if a trip of these devices might eventually result in a trip of the generating unit. For example, a thermal overcurrent trip on the motor of a coal-conveyor belt could eventually lead to the tripping of the generator, but it does not cause the trip.

In the case where a plant does not have a generator connected station service transformer such that it is normally fed from a system connected station service transformer, is it still the drafting team's intent to exclude the Protection Systems for these system connected auxiliary transformers from scope even when the loss of the normal (system connected) station service transformer will result in a trip of a BES generating Facility?

The SDT does not intend that the system-connected station service transformers be included in the Applicability. The generator-connected station service transformers and generator connected excitation transformers are often connected to the generator bus directly without an interposing breaker; thus, the Protection Systems on these transformers will trip the generator as discussed in 4.2.5.1.

What is meant by "verify operation of the relay inputs and outputs that are essential to proper functioning of the Protection System?"

Any input or output (of the relay) that "affects the tripping" of the breaker is included in the scope of I/O of the relay to be verified. By "affects the tripping," one needs to realize that sometimes there are more inputs and outputs than simply the output to the trip coil. Many important protective functions include things like breaker fail initiation, zone timer initiation and sometimes even 52a/b contact inputs are needed for a protective relay to correctly operate.

Each input should be "picked up" or "turned on and off" and verified as changing state by the microprocessor of the relay. Each output should be "operated" or "closed and opened" from the microprocessor of the relay and the output should be verified to change state on the output terminals of the relay. One possible method of testing inputs of these relays is to "jumper" the needed dc voltage to the input and verify that the relay registered the change of state.

Electromechanical lock-out relays (86) (used to convey the tripping current to the trip coils) need to be electrically operated to prove the capability of the device to change state. These tests need to be accomplished at least every six years, unless PBM methodology is applied.

The contacts on the 86 or auxiliary tripping relays (94) that change state to pass on the trip current to a breaker trip coil need only be checked every 12 years with the control circuitry.

What is the difference between a distributed UFLS/UVLS and a non-distributed UFLS/UVLS scheme?

A distributed UFLS or UVLS scheme contains individual relays which make independent Load shed decisions based on applied settings and localized voltage and/or current inputs. A distributed scheme may involve an enable/disable contact in the scheme and still be considered a distributed scheme. A non-distributed UFLS or UVLS scheme involves a system where there is some type of centralized measurement and Load shed decision being made. A non-distributed UFLS/UVLS scheme is considered similar to an SPS scheme and falls under Table 1 for maintenance activities and intervals.

8.2 Retention of Records

PRC-005-1 describes a reporting or auditing cycle of one year and retention of records for three years. However, with a three-year retention cycle, the records of verification for a Protection System might be discarded before the next verification, leaving no record of what was done if a Misoperation or failure is to be analyzed.

PRC-005-X corrects this by requiring:

The Transmission Owner, Generator Owner, and Distribution Provider shall each retain documentation of the most recent performance of each distinct maintenance activity for the Protection System, Automatic Reclosing, or Sudden Pressure Relaying Component, or to the previous scheduled (on-site) audit date, whichever is longer.

This requirement assures that the documentation shows that the interval between maintenance cycles correctly meets the maintenance interval limits. The requirement is actually alerting the industry to documentation requirements already implemented by audit teams. Evidence of compliance bookending the interval shows interval accomplished instead of proving only your planned interval.

The SDT is aware that, in some cases, the retention period could be relatively long. But, the retention of documents simply helps to demonstrate compliance.

8.2.1 Frequently Asked Questions:

Please clarify the data retention requirements.

The data retention requirements are intended to allow the availability of maintenance records to demonstrate that the time intervals in your maintenance plan were upheld.

Maximum Maintenance Interval	**Data Retention Period**
4 Months, 6 Months,18 Months, or 3 Years	All activities since previous audit

6 Years	All activities since previous audit(assuming a 6 year audit cycle) or most recent performance(assuming 3 year audit cycle), whichever is longer
12 Year	All activities from the most recent performance

If an entity prefers to utilize Performance-Based Maintenance, then statistical data may well be retained for extended periods to assist with future adjustments in time intervals.

If an equipment item is replaced, then the entity can restart the maintenance-time-interval-clock if desired; however, the replacement of equipment does not remove any documentation requirements that would have been required to verify compliance with time-interval requirements. In other words, do not discard maintenance data that goes to verify your work.

The retention of documentation for new and/or replaced equipment is all about proving that the maintenance intervals had been in compliance. For example, a long-range plan of upgrades might lead an entity to ignore required maintenance; retaining the evidence of prior maintenance that existed before any retirements and upgrades proves compliance with the standard.

What does this Maintenance Standard say about commissioning? Is it necessary to have documentation in your maintenance history of the completion of commission testing?

This standard does not establish requirements for commission testing. Commission testing includes all testing activities necessary to conclude that a Facility has been built in accordance with design. While a thorough commission testing program would include, either directly or indirectly, the verification of all those Protection System attributes addressed by the maintenance activities specified in the Tables of PRC-005-X, verification of the adequacy of initial installation necessitates the performance of testing and inspections that go well beyond these routine maintenance activities. For example, commission testing might set baselines for future tests; perform acceptance tests and/or warranty tests; utilize testing methods that are not generally done routinely like staged-Fault-tests.

However, many of the Protection System attributes which are verified during commission testing are not subject to age related or service related degradation, and need not be re-verified within an ongoing maintenance program. Example – it is not necessary to re-verify correct terminal strip wiring on an ongoing basis.

PRC-005-X assumes that thorough commission testing was performed prior to a Protection System being placed in service. PRC-005-X 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.

It should be noted that commission testing frequently is performed by a different organization than that which is responsible for the ongoing maintenance of the Protection System. Furthermore, the commission testing activities will not necessarily correlate directly with the maintenance activities required by the standard. As such, it is very likely that commission testing records will deviate significantly from maintenance records in both form and content;

and, therefore, it is not necessary to maintain commission testing records within the maintenance program documentation.

Notwithstanding the differences in records, an entity would be wise to retain commissioning records to show a maintenance start date. (See below). An entity that requires that their commissioning tests have, at a minimum, the requirements of PRC-005-X would help that entity prove time interval maximums by setting the initial time clock.

How do you determine the initial due date for maintenance?

The initial due date for maintenance should be based upon when a Protection System was tested. Alternatively, an entity may choose to use the date of completion of the commission testing of the Protection System component and the system was placed into service as the starting point in determining its first maintenance due dates. Whichever method is chosen, for newly installed Protection Systems the components should not be placed into service until minimum maintenance activities have taken place.

It is conceivable that there can be a (substantial) difference in time between the date of testing, as compared to the date placed into service. The use of the "Calendar Year" language can help determine the next due date without too much concern about being non-compliant for missing test dates by a small amount (provided your dates are not already at the end of a year). However, if there is a substantial amount of time difference between testing and in-service dates, then the testing date should be followed because it is the degradation of components that is the concern. While accuracy fluctuations may decrease when components are not energized, there are cases when degradation can take place, even though the device is not energized. Minimizing the time between commissioning tests and in-service dates will help.

If I miss two battery inspections four times out of 100 Protection System components on my transmission system, does that count as 2% or 8% when counting Violation Severity Level (VSL) for R3?

The entity failed to complete its scheduled program on two of its 100 Protection System components, which would equate to 2% for application to the VSL Table for Requirement R3. This VSL is written to compare missed components to total components. In this case two components out of 100 were missed, or 2%.

How do I achieve a "grace period" without being out of compliance?

The objective here is to create a time extension within your own PSMP that still does not violate the maximum time intervals stated in the standard. Remember that the maximum time intervals listed in the Tables cannot be extended.

For the purposes of this example, concentrating on just unmonitored protective relays – Table 1-1 specifies a maximum time interval (between the mandated maintenance activities) of six calendar years. Your plan must ensure that your unmonitored relays are tested at least once every six calendar years. You could, within your PSMP, require that your unmonitored relays be tested every four calendar years, with a maximum allowable time extension of 18 calendar months. This allows an entity to have deadlines set for the auto-generation of work orders, but still has the flexibility in scheduling complex work schedules. This also allows for that 18 calendar months to act as a buffer, in effect a grace period within your PSMP, in the event of unforeseen events. You will note that this example of a maintenance plan interval has a planned time of four years; it also has a built-in time extension allowed within the PSMP, and yet does not exceed the maximum time interval allowed by the standard. So while there are no time extensions allowed beyond the standard, an entity can still have substantial flexibility to maintain their Protection System components.

8.3 Basis for Table 1 Intervals

When developing the original *Protection System Maintenance – A Technical Reference* in 2007, the SPCTF collected all available data from Regional Entities (REs) on time intervals recommended for maintenance and test programs. The recommendations vary widely in categorization of relays, defined maintenance actions, and time intervals, precluding development of intervals by averaging. The SPCTF also reviewed the 2005 Report [2] of the IEEE Power System Relaying Committee Working Group I-17 (Transmission Relay System Performance Comparison). Review of the I-17 report shows data from a small number of utilities, with no company identification or means of investigating the significance of particular results.

To develop a solid current base of practice, the SPCTF surveyed its members regarding their maintenance intervals for electromechanical and microprocessor relays, and asked the members to also provide definitively-known data for other entities. The survey represented 470 GW of peak Load, or 4% of the NERC peak Load. Maintenance interval averages were compiled by weighting reported intervals according to the size (based on peak Load) of the reporting utility. Thus, the averages more accurately represent practices for the large populations of Protection Systems used across the NERC regions.

The results of this survey with weighted averaging indicate maintenance intervals of five years for electromechanical or solid state relays, and seven years for unmonitored microprocessor relays.

A number of utilities have extended maintenance intervals for microprocessor relays beyond seven years, based on favorable experience with the particular products they have installed. To provide a technical basis for such extension, the SPCTF authors developed a recommendation of 10 years using the Markov modeling approach from [1], as summarized in Section 8.4. The results of this modeling depend on the completeness of self-testing or monitoring. Accordingly, this extended interval is allowed by Table 1, only when such relays are monitored as specified in the attributes of monitoring contained in Tables 1-1 through 1-5 and Table 2. Monitoring is capable of reporting Protection System health issues that are likely to affect performance within the 10 year time interval between verifications.

It is important to note that, according to modeling results, Protection System availability barely changes as the maintenance interval is varied below the 10-year mark. Thus, reducing the maintenance interval does not improve Protection System availability. With the assumptions of the model regarding how maintenance is carried out, reducing the maintenance interval actually degrades Protection System availability.

8.4 Basis for Extended Maintenance Intervals for Microprocessor Relays

Table 1 allows maximum verification intervals that are extended based on monitoring level. The industry has experience with self-monitoring microprocessor relays that leads to the Table 1 value for a monitored relay, as explained in Section 8.3. To develop a basis for the maximum interval for monitored relays in their *Protection System Maintenance – A Technical Reference*, the SPCTF used the methodology of Reference [1], which specifically addresses optimum routine maintenance intervals. The Markov modeling approach of [1] is judged to be valid for the design and typical failure modes of microprocessor relays.

The SPCTF authors ran test cases of the Markov model to calculate two key probability measures:

- Relay Unavailability - the probability that the relay is out of service due to failure or maintenance activity while the power system Element to be protected is in service.
- Abnormal Unavailability - the probability that the relay is out of service due to failure or maintenance activity when a Fault occurs, leading to failure to operate for the Fault.

The parameter in the Markov model that defines self-monitoring capability is ST (for self-test). ST = 0 if there is no self-monitoring; ST = 1 for full monitoring. Practical ST values are estimated to range from .75 to .95. The SPCTF simulation runs used constants in the Markov model that were the same as those used in [1] with the following exceptions:

Sn, Normal tripping operations per hour = 21600 (reciprocal of normal Fault clearing time of 10 cycles)

Sb, Backup tripping operations per hour = 4320 (reciprocal of backup Fault clearing time of 50 cycles)

Rc, Protected component repairs per hour = 0.125 (8 hours to restore the power system)

Rt, Relay routine tests per hour = 0.125 (8 hours to test a Protection System)

Rr, Relay repairs per hour = 0.08333 (12 hours to complete a Protection System repair after failure)

Experimental runs of the model showed low sensitivity of optimum maintenance interval to these parameter adjustments.

The resulting curves for relay unavailability and abnormal unavailability versus maintenance interval showed a broad minimum (optimum maintenance interval) in the vicinity of 10 years – the curve is flat, with no significant change in either unavailability value over the range of 9, 10, or 11 years. This was true even for a relay mean time between Failures (MTBF) of 50 years, much lower than MTBF values typically published for these relays. Also, the Markov modeling indicates that both the relay unavailability and abnormal unavailability actually become higher with more frequent testing. This shows that the time spent on these more frequent tests yields no failure discoveries that approach the negative impact of removing the relays from service and running the tests.

The PSMT SDT discussed the practical need for “time-interval extensions” or “grace periods” to allow for scheduling problems that resulted from any number of business contingencies. The time interval discussions also focused on the need to reflect industry norms surrounding Generator outage frequencies. Finally, it was again noted that FERC Order 693 demanded maximum time intervals. “Maximum time intervals” by their very term negates any “time-interval extension” or “grace periods.” To recognize the need to follow industry norms on Generator outage frequencies and accommodate a form of time-interval extension, while still following FERC Order 693, the Standard Drafting Team arrived at a six-year interval for the electromechanical relay, instead of the five-year interval arrived at by the SPCTF. The PSMT SDT has followed the FERC directive for a *maximum* time interval and has determined that no extensions will be allowed. Six years has been set for the maximum time interval between manual maintenance activities. This maximum time interval also works well for maintenance cycles that have been in use in generator plants for decades.

For monitored relays, the PSMT SDT notes that the SPCTF called for 10 years as the interval between maintenance activities. This 10-year interval was chosen, even though there was "…no significant change in unavailability value over the range of 9, 10, or 11 years. This was true even for a relay Mean Time between Failures (MTBF) of 50 years…" The Standard Drafting Team again sought to align maintenance activities with known successful practices and outage schedules. The Standard does not allow extensions on any component of the Protection System; thus, the maximum allowed interval for these components has been set to 12 years. Twelve years also fits well into the traditional maintenance cycles of both substations and generator plants.

Also of note is the Table's use of the term "Calendar" in the column for "Maximum Maintenance Interval." The PSMT SDT deemed it necessary to include the term "Calendar" to facilitate annual maintenance planning, scheduling and implementation. This need is the result of known occurrences of system requirements that could cause maintenance schedules to be missed by a few days or weeks. The PSMT SDT chose the term "Calendar" to preclude the need to have schedules be met to the day. An electromechanical protective relay that is maintained in year number one need not be revisited until six years later (year number seven). For example, a relay was maintained April 10, 2008; maintenance would need to be completed no later than December 31, 2014.

Though not a requirement of this standard, to stay in line with many Compliance Enforcement Agencies audit processes an entity should define, within their own PSMP, the entity's use of terms like annual, calendar year, etc. Then, once this is within the PSMP, the entity should abide by their chosen language.

9. Performance-Based Maintenance Process

In lieu of using the Table 1 intervals, a Performance-Based Maintenance process may be used to establish maintenance intervals (*PRC-005 Attachment A Criteria for a Performance-Based Protection System Maintenance Program*). A Performance-Based Maintenance process may justify longer maintenance intervals, or require shorter intervals relative to Table 1. In order to use a Performance-Based Maintenance process, the documented maintenance program must include records of repairs, adjustments, and corrections to covered Protection Systems in order to provide historical justification for intervals, other than those established in Table 1. Furthermore, the asset owner must regularly analyze these records of corrective actions to develop a ranking of causes. Recurrent problems are to be highlighted, and remedial action plans are to be documented to mitigate or eliminate recurrent problems.

Entities with Performance-Based Maintenance track performance of Protection Systems, demonstrate how they analyze findings of performance failures and aberrations, and implement continuous improvement actions. Since no maintenance program can ever guarantee that no malfunction can possibly occur, documentation of a Performance-Based Maintenance program would serve the utility well in explaining to regulators and the public a Misoperation leading to a major System outage event.

A Performance-Based Maintenance program requires auditing processes like those included in widely used industrial quality systems (such as ***ISO 9001-2000, Quality Management Systems — Requirements;*** or applicable parts of the NIST Baldridge National Quality Program). The audits periodically evaluate:

- The completeness of the documented maintenance process
- Organizational knowledge of and adherence to the process
- Performance metrics and documentation of results
- Remediation of issues
- Demonstration of continuous improvement.

In order to opt into a Performance-Based Maintenance (PBM) program, the asset owner must first sort the various Components into population segments. Any population segment must be comprised of at least 60 individual units; if any asset owner opts for PBM, but does not own 60 units to comprise a population, then that asset owner may combine data from other asset owners until the needed 60 units is aggregated. Each population segment must be composed of a grouping of Components of a consistent design standard or particular model or type from a single manufacturer and subjected to similar environmental factors. For example: One segment cannot be comprised of both GE & Westinghouse electro-mechanical lock-out relays; likewise, one segment cannot be comprised of 60 GE lock-out relays, 30 of which are in a dirty environment, and the remaining 30 from a clean environment. This PBM process cannot be applied to batteries, but can be applied to all other Components, including (but not limited to) specific battery chargers, instrument transformers, trip coils and/or control circuitry (etc.).

9.1 Minimum Sample Size

Large Sample Size

An assumption that needs to be made when choosing a sample size is "the sampling distribution of the sample mean can be approximated by a normal probability distribution." The Central Limit Theorem states: "In selecting simple random samples of size *n* from a population, the sampling distribution of the sample mean *x* can be approximated by a normal probability distribution as the sample size becomes large." (Essentials of Statistics for Business and Economics, Anderson, Sweeney, Williams, 2003.)

To use the Central Limit Theorem in statistics, the population size should be large. The references below are supplied to help define what is large.

> "… whenever we are using a large simple random sample (rule of thumb: n>=30), the central limit theorem enables us to conclude that the sampling distribution of the sample mean can be approximated by a normal distribution." (Essentials of Statistics for Business and Economics, Anderson, Sweeney, Williams, 2003.)
>
> "If samples of size n, when n>=30, are drawn from any population with a mean *u* and a standard deviation σ, the sampling distribution of sample means approximates a normal distribution. The greater the sample size, the better the approximation." (Elementary Statistics - Picturing the World, Larson, Farber, 2003.)
>
> "The sample size is large (generally n>=30)… (Introduction to Statistics and Data Analysis - Second Edition, Peck, Olson, Devore, 2005.)
>
> "… the normal is often used as an approximation to the *t* distribution in a test of a null hypothesis about the mean of a normally distributed population when the population variance is estimated from a relatively large sample. A sample size exceeding 30 is often given as a minimal size in this connection." (Statistical Analysis for Business Decisions, Peters, Summers, 1968.)

Error of Distribution Formula

Beyond the large sample size discussion above, a sample size requirement can be estimated using the bound on the Error of Distribution Formula when the expected result is of a "Pass/Fail" format and will be between 0 and 1.0.

The Error of Distribution Formula is:

$$B = z\sqrt{\frac{\pi(1-\pi)}{n}}$$

Where:

B = bound on the error of distribution (allowable error)

z = standard error

π = expected failure rate

n = sample size required

Solving for n provides:

$$n = \pi(1-\pi)\left(\frac{z}{B}\right)^2$$

Minimum Population Size to use Performance-Based Program

One entity's population of components should be large enough to represent a sizeable sample of a vendor's overall population of manufactured devices. For this reason, the following assumptions are made:

B = 5%

z = 1.96 (This equates to a 95% confidence level)

π = 4%

Using the equation above, n=59.0.

Minimum Sample Size to evaluate Performance-Based Program

The number of components that should be included in a sample size for evaluation of the appropriate testing interval can be smaller because a lower confidence level is acceptable since the sample testing is repeated or updated annually. For this reason, the following assumptions are made:

B = 5%

z = 1.44 (85% confidence level)

π = 4%

Using the equation above, n=31.8.

Recommendation

Based on the above discussion, a sample size should be at least 30 to allow use of the equation mentioned. Using this and the results of the equation, the following numbers are recommended (and required within the standard):

Minimum Population Size to use Performance-Based Maintenance Program = 60

Minimum Sample Size to evaluate Performance-Based Program = 30.

Once the population segment is defined, then maintenance must begin within the intervals as outlined for the device described in the Tables 1-1 through 1-5. Time intervals can be lengthened provided the last year's worth of components tested (or the last 30 units maintained, whichever is more) had fewer than 4% Countable Events. It is notable that 4% is specifically chosen because an entity with a small population (30 units) would have to adjust its time intervals between maintenance if more than one Countable Event was found to have occurred during the last analysis period. A smaller percentage would require that entity to adjust the time interval between maintenance activities if even one unit is found out of tolerance or causes a Misoperation.

The minimum number of units that can be tested in any given year is 5% of the population. Note that this 5% threshold sets a practical limitation on total length of time between intervals at 20 years.

If at any time the number of Countable Events equals or exceeds 4% of the last year's tested components (or the last 30 units maintained, whichever is more), then the time period between manual maintenance activities must be decreased. There is a time limit on reaching the decreased time at which the Countable Events is less than 4%; this must be attained within three years.

Performance-Based Program Evaluation Example

The 4% performance target was derived as a protection system performance target and was selected based on the drafting team's experience and studies performed by several utilities. This is not derived from the performance of discrete devices. Microprocessor relays and electromechanical relays have different performance levels. It is not appropriate to compare these performance levels to each other. The performance of the segment should be compared to the 4% performance criteria.

In consideration of the use of Performance Based Maintenance (PBM), the user should consider the effects of extended testing intervals and the established 4% failure rate. In the table shown below, the segment is 1000 units. As the testing interval (in years) increases, the number of units tested each year decreases. The number of countable events allowed is 4% of the tested units. Countable events are the failure of a Component requiring repair or replacement, any corrective actions performed during the maintenance test on the units within the testing segment (units per year), or any misoperation attributable to hardware failure or calibration failure found within the entire segment (1000 units) during the testing year.

Example: 1000 units in the segment with a testing interval of 8 years: The number of units tested each year will be 125 units. The total allowable countable events equals: 125 X .04 = 5. This number includes failure of a Component requiring repair or replacement, corrective issues found during testing, and the total number of misoperations (attributable to hardware or calibration failure within the testing year) associated with the entire segment of 1000 units.

Example: 1000 units in the segment with a testing interval of 16 years: The number of units tested each year will be 63 units. The total allowable countable events equals: 63 X .04 = 2.5.

As shown in the above examples, doubling the testing interval reduces the number of allowable events by half.

Total number of units in the segment	1000
Failure rate	4.00%

Testing Intervals (Years)	Units Per Year	Acceptable Number of Countable Events per year	Yearly Failure Rate Based on 1000 Units in Segment
1	1000.00	40.00	4.00%
2	500.00	20.00	2.00%
4	250.00	10.00	1.00%
6	166.67	6.67	0.67%
8	125.00	5.00	0.50%
10	100.00	4.00	0.40%
12	83.33	3.33	0.33%
14	71.43	2.86	0.29%
16	62.50	2.50	0.25%
18	55.56	2.22	0.22%
20	50.00	2.00	0.20%

Using the prior year's data, determine the maximum allowable maintenance interval for each Segment such that the Segment experiences Countable Events on no more than 4% of the Components within the Segment, for the greater of either the last 30 Components maintained or all Components maintained in the previous year.

Segment – Components of a consistent design standard, or a particular model or type from a single manufacturer that typically share other common elements. Consistent performance is expected across the entire population of a Segment. A Segment must contain at least sixty (60) individual Components.

Countable Event – A failure of a Component requiring repair or replacement, any condition discovered during the maintenance activities in Tables 1-1 through 1-5, Table 3, Table 4-1 through Table 4-2, and Table 5, which requires corrective action or a Protection System Misoperation attributed to hardware failure or calibration failure. Misoperations due to product design errors, software errors, relay settings different from specified settings, Protection System Component, Automatic Reclosing, or Sudden Pressure Relaying configuration or application errors are not included in Countable Events.

9.2 Frequently Asked Questions:

I'm a small entity and cannot aggregate a population of Protection System components to establish a segment required for a Performance-Based Protection System Maintenance Program. How can I utilize that opportunity?

Multiple asset owning entities may aggregate their individually owned populations of individual Protection System components to create a segment that crosses ownership boundaries. All entities participating in a joint program should have a single documented joint management

process, with consistent Protection System Maintenance Programs (practices, maintenance intervals and criteria), for which the multiple owners are individually responsible with respect to the requirements of the Standard. The requirements established for Performance-Based Maintenance must be met for the overall aggregated program on an ongoing basis.

The aggregated population should reflect all factors that affect consistent performance across the population, including any relevant environmental factors such as geography, power-plant vs. substation, and weather conditions.

Can an owner go straight to a Performance-Based Maintenance program schedule, if they have previously gathered records?

Yes. An owner can go to a Performance-Based Maintenance program immediately. The owner will need to comply with the requirements of a Performance-Based Maintenance program as listed in the Standard. Gaps in the data collected will not be allowed; therefore, if an owner finds that a gap exists such that they cannot prove that they have collected the data as required for a Performance-Based Maintenance program then they will need to wait until they can prove compliance.

When establishing a Performance-Based Maintenance program, can I use test data from the device manufacturer, or industry survey results, as results to help establish a basis for my Performance-Based intervals?

No, you must use actual in-service test data for the components in the segment.

What types of Misoperations or events are not considered Countable Events in the Performance-Based Protection System Maintenance (PBM) Program?

Countable Events are intended to address conditions that are attributed to hardware failure or calibration failure; that is, conditions that reflect deteriorating performance of the component. These conditions include any condition where the device previously worked properly, then, due to changes within the device, malfunctioned or degraded to the point that re-calibration (to within the entity's tolerance) was required.

For this purpose of tracking hardware issues, human errors resulting in Protection System Misoperations during system installation or maintenance activities are not considered Countable Events. Examples of excluded human errors include relay setting errors, design errors, wiring errors, inadvertent tripping of devices during testing or installation, and misapplication of Protection System components. Examples of misapplication of Protection System components include wrong CT or PT tap position, protective relay function misapplication, and components not specified correctly for their installation. Obviously, if one is setting up relevant data about hardware failures then human failures should be eliminated from the hardware performance analysis.

One example of human-error is not pertinent data might be in the area of testing "86" lock-out relays (LOR). "Entity A" has two types of LOR's type "X" and type "Y"; they want to move into a performance based maintenance interval. They have 1000 of each type, so the population variables are met. During electrical trip testing of all of their various schemes over the initial six-year interval they find zero type "X" failures, but human error led to tripping a BES Element 100 times; they find 100 type "Y" failures and had an additional 100 human-error caused tripping incidents. In this example the human-error caused Misoperations should not be used to judge the performance of either type of LOR. Analysis of the data might lead "Entity A" to change time intervals. Type "X" LOR can be placed into extended time interval testing because of its low failure rate (zero failures) while Type "Y" would have to be tested more often than every 6 calendar years (100 failures divided by 1000 units exceeds the 4% tolerance level).

Certain types of Protection System component errors that cause Misoperations are not considered Countable Events. Examples of excluded component errors include device malfunctions that are correctable by firmware upgrades and design errors that do not impact protection function.

What are some examples of methods of correcting segment perfomance for Performance-Based Maintenance?

There are a number of methods that may be useful for correcting segment performance for mal-performing segments in a Performance-Based Maintenance system. Some examples are listed below.

- The maximum allowable interval, as established by the Performance-Based Maintenance system, can be decreased. This may, however, be slow to correct the performance of the segment.
- Identifiable sub-groups of components within the established segment, which have been identified to be the mal-performing portion of the segment, can be broken out as an independent segment for target action. Each resulting segment must satisfy the minimum population requirements for a Performance-Based Maintenance program in order to remain within the program.
- Targeted corrective actions can be taken to correct frequently occurring problems. An example would be replacement of capacitors within electromechanical distance relays if bad capacitors were determined to be the cause of the mal-performance.
- components within the mal-performing segment can be replaced with other components (electromechanical distance relays with microprocessor relays, for example) to remove the mal-performing segment.

If I find (and correct) a Unresolved Maintenance Issue as a result of a Misoperation investigation (Re: PRC-004), how does this affect my Performance-Based Maintenance program?

If you perform maintenance on a Protection System component for any reason (including as part of a PRC-004 required Misoperation investigation/corrective action), the actions performed can count as a maintenance activity provided the activities in the relevant Tables have been done, and, if you desire, "reset the clock" on everything you've done. In a Performance-Based Maintenance program, you also need to record the Unresolved Maintenance Issue as a Countable Event within the relevant component group segment and use it in the analysis to determine your correct Performance-Based Maintenance interval for that component group. Note that "resetting the clock" should not be construed as interfering with an entity's routine testing schedule because the "clock-reset" would actually make for a decreased time interval by the time the next routine test schedule comes around.

For example a relay scheme, consisting of four relays, is tested on 1-1-11 and the PSMP has a time interval of 3 calendar years with an allowable extension of 1 calendar year. The relay would be due again for routine testing before the end of the year 2015. This mythical relay scheme has a Misoperation on 6-1-12 that points to one of the four relays as bad. Investigation proves a bad relay and a new one is tested and installed in place of the original. This replacement relay actually could be retested before the end of the year 2016 (clock-reset) and not be out of compliance. This requires tracking maintenance by individual relays and is allowed. However, many companies schedule maintenance in other ways like by substation or by circuit breaker or by relay scheme. By these methods of tracking maintenance that “replaced relay” will be retested before the end of the year 2015. This is also acceptable. In no case was a particular relay tested beyond the PSMP of four years max, nor was the 6 year max of the Standard exceeded. The entity can reset the clock if they desire or the entity can continue with original schedules and, in effect, test even more frequently.

Why are batteries excluded from PBM? What about exclusion of batteries from condition based maintenance?

Batteries are the only element of a Protection System that is a perishable item with a shelf life. As a perishable item batteries require not only a constant float charge to maintain their freshness (charge), but periodic inspection to determine if there are problems associated with their aging process and testing to see if they are maintaining a charge or can still deliver their rated output as required.

Besides being perishable, a second unique feature of a battery that is unlike any other Protection System element is that a battery uses chemicals, metal alloys, plastics, welds, and bonds that must interact with each other to produce the constant dc source required for Protection Systems, undisturbed by ac system Disturbances.

No type of battery manufactured today for Protection System application is free from problems that can only be detected over time by inspection and test. These problems can arise from variances in the manufacturing process, chemicals and alloys used in the construction of the individual cells, quality of welds and bonds to connect the components, the plastics used to make batteries and the cell forming process for the individual battery cells.

Other problems that require periodic inspection and testing can result from transportation from the factory to the job site, length of time before a charge is put on the battery, the method of installation, the voltage level and duration of equalize charges, the float voltage level used, and the environment that the battery is installed in.

All of the above mentioned factors and several more not discussed here are beyond the control of the Functional Entities that want to use a Performance-Based Protection System Maintenance (PBM) program. These inherent variances in the aging process of a battery cell make establishment of a designated segment based on manufacturer and type of battery impossible.

The whole point of PBM is that if all variables are isolated then common aging and performance criteria would be the same. However, there are too many variables in the electrochemical process to completely isolate all of the performance-changing criteria.

Similarly, Functional Entities that want to establish a condition-based maintenance program using the highest levels of monitoring, resulting in the least amount of hands-on maintenance activity, cannot completely eliminate some periodic maintenance of the battery used in a station dc supply. Inspection of the battery is required on a Maximum Maintenance Interval listed in the tables due to the aging processes of station batteries. However, higher degrees of

monitoring of a battery can eliminate the requirement for some periodic testing and some inspections (see Table 1-4).

Please provide an example of the calculations involved in extending maintenance time intervals using PBM.

Entity has 1000 GE-HEA lock-out relays; this is greater than the minimum sample requirement of 60. They start out testing all of the relays within the prescribed Table requirements (6 year max) by testing the relays every 5 years. The entity's plan is to test 200 units per year; this is greater than the minimum sample size requirement of 30. For the sake of example only the following will show 6 failures per year, reality may well have different numbers of failures every year. PBM requires annual assessment of failures found per units tested. After the first year of tests the entity finds 6 failures in the 200 units tested. 6/200= 3% failure rate. This entity is now allowed to extend the maintenance interval if they choose. The entity chooses to extend the maintenance interval of this population segment out to 10 years. This represents a rate of 100 units tested per year; entity selects 100 units to be tested in the following year. After that year of testing these 100 units the entity again finds 6 failed units. 6/100= 6% failures. This entity has now exceeded the acceptable failure rate for these devices and must accelerate testing of all of the units at a higher rate such that the failure rate is found to be less than 4% per year; the entity has three years to get this failure rate down to 4% or less (per year). In response to the 6% failure rate, the entity decreases the testing interval to 8 years. This means that they will now test 125 units per year (1000/8). The entity has just two years left to get the test rate corrected.

After a year, they again find six failures out of the 125 units tested. 6/125= 5% failures. In response to the 5% failure rate, the entity decreases the testing interval to seven years. This means that they will now test 143 units per year (1000/7). The entity has just one year left to get the test rate corrected. After a year, they again find six failures out of the 143 units tested. 6/143= 4.2% failures.

(Note that the entity has tried five years and they were under the 4% limit and they tried seven years and they were over the 4% limit. They must be back at 4% failures or less in the next year so they might simply elect to go back to five years.)

Instead, in response to the 5% failure rate, the entity decreases the testing interval to six years. This means that they will now test 167 units per year (1000/6). After a year, they again find six failures out of the 167 units tested. 6/167= 3.6% failures. Entity found that they could maintain the failure rate at no more than 4% failures by maintaining the testing interval at six years or less. Entity chose six-year interval and effectively extended their TBM (five years) program by 20%.

A note of practicality is that an entity will probably be in better shape to lengthen the intervals between tests if the failure rate is less than 2%. But the requirements allow for annual adjustments, if the entity desires. As a matter of maintenance management, an ever-changing test rate (units tested/year) may be un-workable.

Note that the "5% of components" requirement effectively sets a practical limit of 20 year maximum PBM interval. Also of note is the "3 years" requirement; an entity might arbitrarily extend time intervals from six years to 20 years. In the event that an entity finds a failure rate greater than 4%, then the test rate must be accelerated such that within three years the failure rate must be brought back down to 4% or less.

Here is a table that demonstrates the values discussed:

Year #	Total Population (P)	Test Interval (I)	Units to be Tested (U= P/I)	# of Failures Found (F)	Failure Rate (=F/U)	Decision to Change Interval Yes or No	Interval Chosen
1	1000	5 yrs	200	6	3%	Yes	10 yrs
2	1000	10 yrs	100	6	6%	Yes	8 yrs
3	1000	8 yrs	125	6	5%	Yes	7 yrs
4	1000	7 yrs	143	6	4.2%	Yes	6 yrs
5	1000	6 yrs	167	6	3.6%	No	6 yrs

Please provide an example of the calculations involved in extending maintenance time intervals using PBM for control circuitry.

Note that the following example captures "Control Circuitry" as all of the trip paths associated with a particular trip coil of a circuit breaker. An entity is not restricted to this method of counting control circuits. Perhaps another method an entity would prefer would be to simply track every individual (parallel) trip path. Or perhaps another method would be to track all of the trip outputs from a specific (set) of relays protecting a specific element. ~~Under the included definition of "component":~~

The designation of what constitutes a control circuit component is very dependent upon how an entity performs and tracks the testing of the control circuitry. Some entities test their control circuits on a breaker basis whereas others test their circuitry on a local zone of protection basis. Thus, entities are allowed the latitude to designate their own definitions of control circuit components. Another example of where the entity has some discretion on determining what constitutes a single component is the voltage and current sensing devices, where the entity may choose either to designate a full three-phase set of such devices or a single device as a single component.

And in Attachment A (PBM) the definition of Segment:

Segment –*Components of a consistent design standard, or a particular model or type from a single manufacturer that typically share other common elements. Consistent performance is expected across the entire population of a segment. A segment must contain at least sixty (60) individual components.*

Example:

Entity has 1,000 circuit breakers, all of which have two trip coils, for a total of 2,000 trip coils; if all circuitry was designed and built with a consistent (internal entity) standard, then this is greater than the minimum sample requirement of 60.

For the sake of further example, the following facts are given:

Half of all relay panels (500) were built 40 years ago by an outside contractor, consisted of asbestos wrapped 600V-insulation panel wiring, and the cables exiting the control house are THHN pulled in conduit direct to exactly half of all of the various circuit breakers. All of the relay panels and cable pulls were built with consistent standards and consistent performance standard expectations within the segment (which is greater than 60). Each relay panel has redundant microprocessor (MPC) relays (retrofitted); each MPC relay supplies an individual trip output to each of the two trip coils of the assigned circuit breaker.

Approximately 35 years ago, the entity developed their own internal construction crew and now builds all of their own relay panels from parts supplied from vendors that meet the entity's specifications, including SIS 600V insulation wiring and copper-sheathed cabling within the direct conduits to circuit breakers. The construction crew uses consistent standards in the construction. This newer segment of their control circuitry population is different than the original segment, consistent (standards, construction and performance expectations) within the new segment and constitutes the remainder of the entity's population (another 500 panels and the cabling to the remaining 500 circuit breakers). Each relay panel has redundant microprocessor (MPC) relays; each MPC relay supplies an individual trip output to each of the two trip coils of the assigned circuit breaker. Every trip path in this newer segment has a device that monitors the voltage directly across the trip contacts of the MPC relays and alarms via RTU and SCADA to the operations control room. This monitoring device, when not in alarm, demonstrates continuity all the way through the trip coil, cabling and wiring back to the trip contacts of the MPC relay.

The entity is tracking 2,000 trip coils (each consisting of multiple trip paths) in each of these two segments. But half of all of the trip paths are monitored; therefore, the trip paths are continuously tested and the circuit will alarm when there is a failure. These alarms have to be verified every 12 years for correct operation.

The entity now has 1,000 trip coils (and associated trip paths) remaining that they have elected to count as control circuits. The entity has instituted a process that requires the verification of every trip path to each trip coil (one unit), including the electrical activation of the trip coil. (The entity notes that the trip coils will have to be tripped electrically more often than the trip path verification, and is taking care of this activity through other documentation of Real-time Fault operations.)

They start out testing all of the trip coil circuits within the prescribed Table requirements (12-year max) by testing the trip circuits every 10 years. The entity's plan is to test 100 units per year; this is greater than the minimum sample size requirement of 30. For the sake of example only, the following will show three failures per year; reality may well have different numbers of failures every year. PBM requires annual assessment of failures found per units tested. After the first year of tests, the entity finds three failures in the 100 units tested. 3/100= 3% failure rate.

This entity is now allowed to extend the maintenance interval, if they choose. The entity chooses to extend the maintenance interval of this population segment out to 20 years. This represents a rate of 50 units tested per year; entity selects 50 units to be tested in the following year. After that year of testing these 50 units, the entity again finds three failed units. 3/50= 6% failures.

This entity has now exceeded the acceptable failure rate for these devices and must accelerate testing of all of the units at a higher rate, such that the failure rate is found to be less than 4% per year; the entity has three years to get this failure rate down to 4% or less (per year).

In response to the 6% failure rate, the entity decreases the testing interval to 16 years. This means that they will now test 63 units per year (1000/16). The entity has just two years left to get the test rate corrected. After a year, they again find three failures out of the 63 units tested. 3/63= 4.76% failures.

In response to the >4% failure rate, the entity decreases the testing interval to 14 years. This means that they will now test 72 units per year (1000/14). The entity has just one year left to get the test rate corrected. After a year, they again find three failures out of the 72 units tested. 3/72= 4.2% failures.

(Note that the entity has tried 10 years, and they were under the 4% limit; and they tried 14 years, and they were over the 4% limit. They must be back at 4% failures or less in the next year, so they might simply elect to go back to 10 years.)

Instead, in response to the 4.2% failure rate, the entity decreases the testing interval to 12 years. This means that they will now test 84 units per year (1000/12). After a year, they again find three failures out of the 84 units tested. 3/84= 3.6% failures.

Entity found that they could maintain the failure rate at no more than 4% failures by maintaining the testing interval at 12 years or less. Entity chose 12-year interval, and effectively extended their TBM (10 years) program by 20%.

A note of practicality is that an entity will probably be in better shape to lengthen the intervals between tests if the failure rate is less than 2%. But the requirements allow for annual adjustments if the entity desires. As a matter of maintenance management, an ever-changing test rate (units tested / year) may be un-workable.

Note that the "5% of components" requirement effectively sets a practical limit of 20-year maximum PBM interval. Also of note is the "3 years" requirement; an entity might arbitrarily extend time intervals from six years to 20 years. In the event that an entity finds a failure rate greater than 4%, then the test rate must be accelerated such that within three years the failure rate must be brought back down to 4% or less.

Here is a table that demonstrates the values discussed:

Year #	Total Population (P)	Test Interval (I)	Units to be Tested (U= P/I)	# of Failures Found (F)	Failure Rate (=F/U)	Decision to Change Interval Yes or No	Interval Chosen
1	1000	10 yrs	100	3	3%	Yes	20 yrs
2	1000	20 yrs	50	3	6%	Yes	16yrs
3	1000	16 yrs	63	3	4.8%	Yes	14 yrs
4	1000	14 yrs	72	3	4.2%	Yes	12 yrs
5	1000	12 yrs	84	3	3.6%	No	12 yrs

Please provide an example of the calculations involved in extending maintenance time intervals using PBM for voltage and current sensing devices.

Note that the following example captures "voltage and current inputs to the protective relays" as all of the various current transformer and potential transformer signals associated with a particular set of relays used for protection of a specific Element. This entity calls this set of protective relays a "Relay Scheme." Thus, this entity chooses to count PT and CT signals as a group instead of individually tracking maintenance activities to specific bushing CT's or specific PT's. An entity is not restricted to this method of counting voltage and current devices, signals and paths. Perhaps another method an entity would prefer would be to simply track every individual PT and CT. Note that a generation maintenance group may well select the latter because they may elect to perform routine off-line tests during generator outages, whereas a transmission maintenance group might create a process that utilizes Real-time system values measured at the relays. ~~Under the included definition of "component":~~

The designation of what constitutes a control circuit component is very dependent upon how an entity performs and tracks the testing of the control circuitry. Some entities test their control circuits on a breaker basis whereas others test their circuitry on a local zone of protection basis. Thus, entities are allowed the latitude to designate their own definitions of control circuit components. Another example of where the entity has some discretion on determining what constitutes a single component is the voltage and current sensing devices, where the entity may choose either to designate a full three-phase set of such devices or a single device as a single component.

And in Attachment A (PBM) the definition of Segment:

Segment –*Components of a consistent design standard, or a particular model or type from a single manufacturer that typically share other common elements. Consistent performance is expected across the entire population of a segment. A segment must contain at least sixty (60) individual components.*

Example:

Entity has 2000 "Relay Schemes," all of which have three current signals supplied from bushing CTs, and three voltage signals supplied from substation bus PT's. All cabling and circuitry was designed and built with a consistent (internal entity) standard, and this population is greater than the minimum sample requirement of 60.

For the sake of further example the following facts are given:

Half of all relay schemes (1,000) are supplied with current signals from ANSI STD C800 bushing CTs and voltage signals from PTs built by ACME Electric MFR CO. All of the relay panels and cable pulls were built with consistent standards, and consistent performance standard expectations exist for the consistent wiring, cabling and instrument transformers within the segment (which is greater than 60).

The other half of the entity's relay schemes have MPC relays with additional monitoring built-in that compare DNP values of voltages and currents (or Watts and VARs), as interpreted by the MPC relays and alarm for an entity-accepted tolerance level of accuracy. This newer segment of their "Voltage and Current Sensing" population is different than the original segment, consistent (standards, construction and performance expectations) within the new segment and constitutes the remainder of the entity's population.

The entity is tracking many thousands of voltage and current signals within 2,000 relay schemes (each consisting of multiple voltage and current signals) in each of these two segments. But half of all of the relay schemes voltage and current signals are monitored; therefore, the voltage and current signals are continuously tested and the circuit will alarm when there is a failure; these alarms have to be verified every 12 years for correct operation.

The entity now has 1,000 relay schemes worth of voltage and current signals remaining that they have elected to count within their relay schemes designation. The entity has instituted a process that requires the verification of these voltage and current signals within each relay scheme (one unit).

(Please note - a problem discovered with a current or voltage signal found at the relay could be caused by anything from the relay, all the way to the signal source itself. Having many sources of problems can easily increase failure rates beyond the rate of failures of just one item (for example just PTs). It is the intent of the SDT to minimize failure rates of all of the equipment to an acceptable level; thus, any failure of any item that gets the signal from source to relay is counted. It is for this reason that the SDT chose to set the boundary at the ability of the signal to be delivered all the way to the relay.

The entity will start out measuring all of the relay scheme voltage and currents at the individual relays within the prescribed Table requirements (12 year max) by measuring the voltage and current values every 10 years. The entity's plan is to test 100 units per year; this is greater than the minimum sample size requirement of 30. For the sake of example only, the following will show three failures per year; reality may well have different numbers of failures every year. PBM requires annual assessment of failures found per units tested. After the first year of tests, the entity finds three failures in the 100 units tested. 3/100= 3% failure rate.

This entity is now allowed to extend the maintenance interval, if they choose. The entity chooses to extend the maintenance interval of this population segment out to 20 years. This represents a rate of 50 units tested per year; entity selects 50 units to be tested in the following year. After that year of testing these 50 units, the entity again finds three failed units. 3/50= 6% failures.

This entity has now exceeded the acceptable failure rate for these devices and must accelerate testing of all of the units at a higher rate, such that the failure rate is found to be less than 4% per year; the entity has three years to get this failure rate down to 4% or less (per year).

In response to the 6% failure rate, the entity decreases the testing interval to 16 years. This means that they will now test 63 units per year (1000/16). The entity has just two years left to get the test rate corrected. After a year, they again find three failures out of the 63 units tested. 3/63= 4.76% failures.

In response to the >4%failure rate, the entity decreases the testing interval to 14 years. This means that they will now test 72 units per year (1000/14). The entity has just one year left to get the test rate corrected. After a year, they again find three failures out of the 72 units tested. 3/72= 4.2% failures.

(Note that the entity has tried 10 years, and they were under the 4% limit; and they tried 14 years, and they were over the 4% limit. They must be back at 4% failures or less in the next year, so they might simply elect to go back to 10 years.)

Instead, in response to the 4.2% failure rate, the entity decreases the testing interval to 12 years. This means that they will now test 84 units per year (1,000/12). After a year, they again find three failures out of the 84 units tested. 3/84= 3.6% failures.

Entity found that they could maintain the failure rate at no more than 4% failures by maintaining the testing interval at 12 years or less. Entity chose 12-year interval and effectively extended their TBM (10 years) program by 20%.

A note of practicality is that an entity will probably be in better shape to lengthen the intervals between tests if the failure rate is less than 2%. But the requirements allow for annual adjustments, if the entity desires. As a matter of maintenance management, an ever-changing test rate (units tested/year) may be un-workable.

Note that the "5% of components" requirement effectively sets a practical limit of 20-year maximum PBM interval. Also of note is the "3 years" requirement; an entity might arbitrarily extend time intervals from six years to 20 years. In the event that an entity finds a failure rate greater than 4%, then the test rate must be accelerated such that within three years the failure rate must be brought back down to 4% or less.

Here is a table that demonstrates the values discussed:

Year #	Total Population (P)	Test Interval (I)	Units to be Tested (U= P/I)	# of Failures Found (F)	Failure Rate (=F/U)	Decision to Change Interval Yes or No	Interval Chose
1	1000	10 yrs	100	3	3%	Yes	20 yrs
2	1000	20 yrs	50	3	6%	Yes	16yrs
3	1000	16 yrs	63	3	4.8%	Yes	14 yrs
4	1000	14 yrs	72	3	4.2%	Yes	12 yrs
5	1000	12 yrs	84	3	3.6%	No	12 yrs

10. Overlapping the Verification of Sections of the Protection System

Tables 1-1 through 1-5 require that every Protection System component be periodically verified. One approach, but not the only method, is to test the entire protection scheme as a unit, from the secondary windings of voltage and current sources to breaker tripping. For practical ongoing verification, sections of the Protection System may be tested or monitored individually. The boundaries of the verified sections must overlap to ensure that there are no gaps in the verification. See Appendix A of this Supplementary Reference for additional discussion on this topic.

All of the methodologies expressed within this report may be combined by an entity, as appropriate, to establish and operate a maintenance program. For example, a Protection System may be divided into multiple overlapping sections with a different maintenance methodology for each section:

- Time-based maintenance with appropriate maximum verification intervals for categories of equipment, as given in the Tables 1-1 through 1-5;
- Monitoring as described in Tables 1-1 through 1-5;
- A Performance-Based Maintenance program as described in Section 9 above, or Attachment A of the standard;
- Opportunistic verification using analysis of Fault records, as described in Section 11

10.1 Frequently Asked Questions:

My system has alarms that are gathered once daily through an auto-polling system; this is not really a conventional SCADA system but does it meet the Table 1 requirements for inclusion as a monitored system?

Yes, provided the auto-polling that gathers the alarms reports those alarms to a location where the action can be initiated to correct the Unresolved Maintenance Issue. This location does not have to be the location of the engineer or the technician that will eventually repair the problem, but rather a location where the action can be initiated.

11. Monitoring by Analysis of Fault Records

Many users of microprocessor relays retrieve Fault event records and oscillographic records by data communications after a Fault. They analyze the data closely if there has been an apparent Misoperation, as NERC standards require. Some advanced users have commissioned automatic Fault record processing systems that gather and archive the data. They search for evidence of component failures or setting problems hidden behind an operation whose overall outcome seems to be correct. The relay data may be augmented with independently captured Digital Fault Recorder (DFR) data retrieved for the same event.

Fault data analysis comprises a legitimate CBM program that is capable of reducing the need for a manual time-interval based check on Protection Systems whose operations are analyzed. Even electromechanical Protection Systems instrumented with DFR channels may achieve some CBM benefit. The completeness of the verification then depends on the number and variety of Faults in the vicinity of the relay that produce relay response records and the specific data captured.

A typical Fault record will verify particular parts of certain Protection Systems in the vicinity of the Fault. For a given Protection System installation, it may or may not be possible to gather within a reasonable amount of time an ensemble of internal and external Fault records that completely verify the Protection System.

For example, Fault records may verify that the particular relays that tripped are able to trip via the control circuit path that was specifically used to clear that Fault. A relay or DFR record may indicate correct operation of the protection communications channel. Furthermore, other nearby Protection Systems may verify that they restrain from tripping for a Fault just outside their respective zones of protection. The ensemble of internal Fault and nearby external Fault event data can verify major portions of the Protection System, and reset the time clock for the Table 1 testing intervals for the verified components only.

What can be shown from the records of one operation is very specific and limited. In a panel with multiple relays, only the specific relay(s) whose operation can be observed without ambiguity should be used. Be careful about using Fault response data to verify that settings or calibration are correct. Unless records have been captured for multiple Faults close to either side of a setting boundary, setting or calibration could still be incorrect.

PMU data, much like DME data, can be utilized to prove various components of the Protection System. Obviously, care must be taken to attribute proof only to the parts of a Protection System that can actually be proven using the PMU or DME data.

If Fault record data is used to show that portions or all of a Protection System have been verified to meet Table 1 requirements, the owner must retain the Fault records used, and the maintenance-related conclusions drawn from this data and used to defer Table 1 tests, for at least the retention time interval given in Section 8.2.

11.1 Frequently Asked Questions:

I use my protective relays for Fault and Disturbance recording, collecting oscillographic records and event records via communications for Fault analysis to meet NERC and DME requirements. What are the maintenance requirements for the relays?

For relays used only as Disturbance Monitoring Equipment, NERC Standard PRC-018-1 R3 & R6 states the maintenance requirements and is being addressed by a standards activity that is revising PRC-002-1 and PRC-018-1. For protective relays "that are designed to provide protection for the BES," this standard applies, even if they also perform DME functions.

12. Importance of Relay Settings in Maintenance Programs

In manual testing programs, many utilities depend on pickup value or zone boundary tests to show that the relays have correct settings and calibration. Microprocessor relays, by contrast, provide the means for continuously monitoring measurement accuracy. Furthermore, the relay digitizes inputs from one set of signals to perform all measurement functions in a single self-monitoring microprocessor system. These relays do not require testing or calibration of each setting.

However, incorrect settings may be a bigger risk with microprocessor relays than with older relays. Some microprocessor relays have hundreds or thousands of settings, many of which are critical to Protection System performance.

Monitoring does not check measuring element settings. Analysis of Fault records may or may not reveal setting problems. To minimize risk of setting errors after commissioning, the user should enforce strict settings data base management, with reconfirmation (manual or automatic) that the installed settings are correct whenever maintenance activity might have changed them; for background and guidance, see [5] in References.

Table 1 requires that settings must be verified to be as specified. The reason for this requirement is simple: With legacy relays (non-microprocessor protective relays), it is necessary to know the value of the intended setting in order to test, adjust and calibrate the relay. Proving that the relay works per specified setting was the de facto procedure. However, with the advanced microprocessor relays, it is possible to change relay settings for the purpose of verifying specific functions and then neglect to return the settings to the specified values. While there is no specific requirement to maintain a settings management process, there remains a need to verify that the settings left in the relay are the intended, specified settings. This need may manifest itself after any of the following:

- One or more settings are changed for any reason.
- A relay fails and is repaired or replaced with another unit.
- A relay is upgraded with a new firmware version.

12.1 Frequently Asked Questions:

How do I approach testing when I have to upgrade firmware of a microprocessor relay?

The entity should ensure that the relay continues to function properly after implementation of firmware changes. Some entities may have a R&D department that might routinely run acceptance tests on devices with firmware upgrades before allowing the upgrade to be installed. Other entities may rely upon the vigorous testing of the firmware OEM. An entity has the latitude to install devices and/or programming that they believe will perform to their satisfaction. If an entity should choose to perform the maintenance activities specified in the Tables following a firmware upgrade, then they may, if they choose, reset the time clock on that set of maintenance activities so that they would not have to repeat the maintenance on its regularly scheduled cycle. (However, for simplicity in maintenance schedules, some entities may choose to not reset this time clock; it is merely a suggested option.)

If I upgrade my old relays, then do I have to maintain my previous equipment maintenance documentation?

If an equipment item is repaired or replaced, then the entity can restart the maintenance-activity-time-interval-clock, if desired; however, the replacement of equipment does not remove any documentation requirements. The requirements in the standard are intended to ensure that an entity has a maintenance plan, and that the entity adheres to minimum activities and maximum time intervals. The documentation requirements are intended to help an entity demonstrate compliance. For example, saving the dates and records of the last two maintenance activities is intended to demonstrate compliance with the interval. Therefore, if you upgrade or replace equipment, then you still must maintain the documentation for the previous equipment, thus demonstrating compliance with the time interval requirement prior to the replacement action.

We have a number of installations where we have changed our Protection System components. Some of the changes were upgrades, but others were simply system rating changes that merely required taking relays "out-of-service". What are our responsibilities when it comes to "out-of-service" devices?

Assuming that your system up-rates, upgrades and overall changes meet any and all other requirements and standards, then the requirements of PRC-005-X are simple – if the Protection System component performs a Protection System function, then it must be maintained. If the component no longer performs Protection System functions, then it does not require maintenance activities under the Tables of PRC-005-X. While many entities might physically remove a component that is no longer needed, there is no requirement in PRC-005-X to remove such component(s). Obviously, prudence would dictate that an "out-of-service" device is truly made inactive. There are no record requirements listed in PRC-005-X for Protection System components not used.

While performing relay testing of a protective device on our Bulk Electric System, it was discovered that the protective device being tested was either broken or out of calibration. Does this satisfy the relay testing requirement, even though the protective device tested bad, and may be unable to be placed back into service?

Yes, PRC-005-X requires entities to perform relay testing on protective devices on a given maintenance cycle interval. By performing this testing, the entity has satisfied PRC-005-X requirement, although the protective device may be unable to be returned to service under normal calibration adjustments. R5 states:

"R5. Each Transmission Owner, Generator Owner, and Distribution Provider shall demonstrate efforts to correct any identified Unresolved Maintenance Issues."

Also, when a failure occurs in a Protection System, power system security may be comprised, and notification of the failure must be conducted in accordance with relevant NERC standards.

If I show the protective device out of service while it is being repaired, then can I add it back as a new protective device when it returns? If not, my relay testing history would show that I was out of compliance for the last maintenance cycle.

The maintenance and testing requirements (R5) state "…shall demonstrate efforts to correct any identified Unresolved Maintenance Issues..." The type of corrective activity is not stated; however, it could include repairs or replacements.

Your documentation requirements will increase, of course, to demonstrate that your device tested bad and had corrective actions initiated. Your regional entity might ask about the status of your corrective actions.

13. Self-Monitoring Capabilities and Limitations

Microprocessor relay proponents have cited the self-monitoring capabilities of these products for nearly 20 years. Theoretically, any element that is monitored does not need a periodic manual test. A problem today is that the community of manufacturers and users has not created clear documentation of exactly what is and is not monitored. Some unmonitored but critical elements are buried in installed systems that are described as self-monitoring.

To utilize the extended time intervals allowed by monitoring, the user must document that the monitoring attributes of the device match the minimum requirements listed in the Table 1.

Until users are able to document how all parts of a system which are required for the protective functions are monitored or verified (with help from manufacturers), they must continue with the unmonitored intervals established in Table 1 and Table 3.

Going forward, manufacturers and users can develop mappings of the monitoring within relays, and monitoring coverage by the relay of user circuits connected to the relay terminals.

To enable the use of the most extensive monitoring (and never again have a hands-on maintenance requirement), the manufacturers of the microprocessor-based self-monitoring components in the Protection System should publish for the user a document or map that shows:

- How all internal elements of the product are monitored for any failure that could impact Protection System performance.
- Which connected circuits are monitored by checks implemented within the product; how to connect and set the product to assure monitoring of these connected circuits; and what circuits or potential problems are not monitored.

This manufacturer's information can be used by the registered entity to document compliance of the monitoring attributes requirements by:

- Presenting or referencing the product manufacturer's documents.
- Explaining in a system design document the mapping of how every component and circuit that is critical to protection is monitored by the microprocessor product(s) or by other design features.
- Extending the monitoring to include the alarm transmission Facilities through which failures are reported within a given time frame to allocate where action can be taken to initiate resolution of the alarm attributed to an Unresolved Maintenance Issue, so that failures of monitoring or alarming systems also lead to alarms and action.
- Documenting the plans for verification of any unmonitored components according to the requirements of Table 1 and Table 3.

13.1 Frequently Asked Questions:

I can't figure out how to demonstrate compliance with the requirements for the highest level of monitoring of Protection Systems. Why does this Maintenance Standard describe a maintenance program approach I cannot achieve?

Demonstrating compliance with the requirements for the highest level of monitoring any particular component of Protection Systems is likely to be very involved, and may include detailed manufacturer documentation of complete internal monitoring within a device, comprehensive design drawing reviews, and other detailed documentation. This standard does not presume to specify what documentation must be developed; only that it must be documented.

There may actually be some equipment available that is capable of meeting these highest levels of monitoring criteria, in which case it may be maintained according to the highest level of monitoring shown on the Tables. However, even if there is no equipment available today that can meet this level of monitoring, the standard establishes the necessary requirements for when such equipment becomes available.

By creating a roadmap for development, this provision makes the standard technology-neutral. The Standard Drafting Team wants to avoid the need to revise the standard in a few years to accommodate technology advances that may be coming to the industry.

14. Notification of Protection System or Automatic Reclosing Failures

When a failure occurs in a Protection System or Automatic Reclosing, power system security may be compromised, and notification of the failure must be conducted in accordance with relevant NERC standard(s). Knowledge of the failure may impact the system operator's decisions on acceptable Loading conditions.

This formal reporting of the failure and repair status to the system operator by the Protection System or Automatic Reclosing owner also encourages the system owner to execute repairs as rapidly as possible. In some cases, a microprocessor relay or carrier set can be replaced in hours; wiring termination failures may be repaired in a similar time frame. On the other hand, a component in an electromechanical or early-generation electronic relay may be difficult to find and may hold up repair for weeks. In some situations, the owner may have to resort to a temporary protection panel, or complete panel replacement.

15. Maintenance Activities

Some specific maintenance activities are a requirement to ensure reliability. An example would be that a BES entity could be prudent in its protective relay maintenance, but if its battery maintenance program is lacking, then reliability could still suffer. The NERC glossary outlines a Protection System as containing specific components. PRC-005-X requires specific maintenance activities be accomplished within a specific time interval. As noted previously, higher technology equipment can contain integral monitoring capability that actually performs maintenance verification activities routinely and often; therefore, *manual intervention* to perform certain activities on these type components may not be needed.

15.1 Protective Relays (Table 1-1)

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 Element of the BES. Devices that sense thermal, vibration, seismic, gas, or any other non-electrical inputs are excluded.

Non-microprocessor based equipment is treated differently than microprocessor-based equipment in the following ways; the relays should meet the asset owners' tolerances:

- Non-microprocessor devices must be tested with voltage and/or current applied to the device.
- Microprocessor devices may be tested through the integral testing of the device.
    - There is no specific protective relay commissioning test or relay routine test mandated.
    - There is no specific documentation mandated.

15.1.1 Frequently Asked Questions:

What calibration tolerance should be applied on electromechanical relays?

Each entity establishes their own acceptable tolerances when applying protective relaying on their system. For some Protection System components, adjustment is required to bring measurement accuracy within the parameters established by the asset owner based on the specific application of the component. A calibration failure is the result if testing finds the specified parameters to be out of tolerance.

15.2 Voltage & Current Sensing Devices (Table 1-3)

These are the current and voltage sensing devices, usually known as instrument transformers. There is presently a technology available (fiber-optic Hall-effect) that does not utilize conventional transformer technology; these devices and other technologies that produce quantities that represent the primary values of voltage and current are considered to be a type of voltage and current sensing devices included in this standard.

The intent of the maintenance activity is to verify the input to the protective relay from the device that produces the current or voltage signal sample.

There is no specific test mandated for these components. The important thing about these signals is to know that the expected output from these components actually reaches the protective relay. Therefore, the proof of the proper operation of these components also demonstrates the integrity of the wiring (or other medium used to convey the signal) from the current and voltage sensing device, all the way to the protective relay. The following observations apply:

- There is no specific ratio test, routine test or commissioning test mandated.
- There is no specific documentation mandated.
- It is required that the signal be present at the relay.
- This expectation can be arrived at from any of a number of means; including, but not limited to, the following: By calculation, by comparison to other circuits, by commissioning tests, by thorough inspection, or by any means needed to verify the circuit meets the asset owner's Protection System maintenance program.
- An example of testing might be a saturation test of a CT with the test values applied at the relay panel; this, therefore, tests the CT, as well as the wiring from the relay all the back to the CT.
- Another possible test is to measure the signal from the voltage and/or current sensing devices, during Load conditions, at the input to the relay.
- Another example of testing the various voltage and/or current sensing devices is to query the microprocessor relay for the Real-time Loading; this can then be compared to other devices to verify the quantities applied to this relay. Since the input devices have supplied the proper values to the protective relay, then the verification activity has been satisfied. Thus, event reports (and oscillographs) can be used to verify that the voltage and current sensing devices are performing satisfactorily.
- Still another method is to measure total watts and VArs around the entire bus; this should add up to zero watts and zero VArs, thus proving the voltage and/or current sensing devices system throughout the bus.
- Another method for proving the voltage and/or current-sensing devices is to complete commissioning tests on all of the transformers, cabling, fuses and wiring.
- Any other method that verifies the input to the protective relay from the device that produces the current or voltage signal sample.

15.2.1 Frequently Asked Questions:

What is meant by "…verify the current and voltage circuit inputs from the voltage and current sensing devices to the protective relays …" Do we need to perform ratio, polarity and saturation tests every few years?

No. You must verify that the protective relay is receiving the expected values from the voltage and current-sensing devices (typically voltage and current transformers). This can be as difficult as is proposed by the question (with additional testing on the cabling and substation wiring to ensure that the values arrive at the relays); or simplicity can be achieved by other verification methods. While some examples follow, these are not intended to represent an all-inclusive list; technology advances and ingenuity should not be excluded from making comparisons and verifications:

- Compare the secondary values, at the relay, to a metering circuit, fed by different current transformers, monitoring the same line as the questioned relay circuit.
- Compare the individual phase secondary values at the relay panel (with additional testing on the panel wiring to ensure that the values arrive at those relays) with the other phases, and verify that residual currents are within expected bounds.
- Observe all three phase currents and the residual current at the relay panel with an oscilloscope, observing comparable magnitudes and proper phase relationship, with additional testing on the panel wiring to ensure that the values arrive at the relays.
- Compare the values, as determined by the questioned relay (such as, but not limited to, a query to the microprocessor relay) to another protective relay monitoring the same line, with currents supplied by different CTs.
- Compare the secondary values, at the relay with values measured by test instruments (such as, but not limited to multi-meters, voltmeter, clamp-on ammeters, etc.) and verified by calculations and known ratios to be the values expected. For example, a single PT on a 100KV bus will have a specific secondary value that, when multiplied by the PT ratio, arrives at the expected bus value of 100KV.
- Query SCADA for the power flows at the far end of the line protected by the questioned relay, compare those SCADA values to the values as determined by the questioned relay.
- Totalize the Watts and VARs on the bus and compare the totals to the values as seen by the questioned relay.

The point of the verification procedure is to ensure that all of the individual components are functioning properly; and that an ongoing proactive procedure is in place to re-check the various components of the protective relay measuring Systems.

Is wiring insulation or hi-pot testing required by this Maintenance Standard?

No, wiring insulation and equipment hi-pot testing are not specifically required by the Maintenance Standard. However, if the method of verifying CT and PT inputs to the relay involves some other method than actual observation of current and voltage transformer secondary inputs to the relay, it might be necessary to perform some sort of cable integrity test to verify that the instrument transformer secondary signals are actually making it to the relay and not being shunted off to ground. For instance, you could use CT excitation tests and PT turns ratio tests and compare to baseline values to verify that the instrument transformer outputs are acceptable. However, to conclude that these acceptable transformer instrument output signals are actually making it to the relay inputs, it also would be necessary to verify the insulation of the wiring between the instrument transformer and the relay.

My plant generator and transformer relays are electromechanical and do not have metering functions, as do microprocessor- based relays. In order for me to compare the instrument transformer inputs to these relays to the secondary values of other metered instrument transformers monitoring the same primary voltage and current signals, it would be necessary to temporarily connect test equipment, like voltmeters and clamp on ammeters, to measure the input signals to the relays. This practice seems very risky, and a plant trip could result if the technician were to make an error while measuring these current and voltage signals. How can I avoid this risk? Also, what if no other instrument transformers are available which monitor the same primary voltage or current signal?

Comparing the input signals to the relays to the outputs of other independent instrument transformers monitoring the same primary current or voltage is just one method of verifying the instrument transformer inputs to the relays, but is not required by the standard. Plants can choose how to best manage their risk. If online testing is deemed too risky, offline tests, such as, but not limited to, CT excitation test and PT turns ratio tests can be compared to baseline data and be used in conjunction with CT and PT secondary wiring insulation verification tests to adequately "verify the current and voltage circuit inputs from the voltage and current sensing devices to the protective relays …" while eliminating the risk of tripping an in service generator or transformer. Similarly, this same offline test methodology can be used to verify the relay input voltage and current signals to relays when there are no other instrument transformers monitoring available for purposes of signal comparison.

15.3 Control circuitry associated with protective functions (Table 1-5)

This component of Protection Systems includes the trip coil(s) of the circuit breaker, circuit switcher or any other interrupting device. It includes the wiring from the batteries to the relays. It includes the wiring (or other signal conveyance) from every trip output to every trip coil. It includes any device needed for the correct processing of the needed trip signal to the trip coil of the interrupting device; this requirement is meant to capture inputs and outputs to and from a protective relay that are necessary for the correct operation of the protective functions. In short, every trip path must be verified; the method of verification is optional to the asset owner. An example of testing methods to accomplish this might be to verify, with a volt-meter, the existence of the proper voltage at the open contacts, the open circuited input circuit and at the trip coil(s). As every parallel trip path has similar failure modes, each trip path from relay to trip coil must be verified. Each trip coil must be tested to trip the circuit breaker (or other interrupting device) at least once. There is a requirement to operate the circuit breaker (or other interrupting device) at least once every six years as part of the complete functional test. If a suitable monitoring system is installed that verifies every parallel trip path, then the manual-intervention testing of those parallel trip paths can be eliminated; however, the actual operation of the circuit breaker must still occur at least once every six years. This six-year tripping requirement can be completed as easily as tracking the Real-time Fault-clearing operations on the circuit breaker, or tracking the trip coil(s) operation(s) during circuit breaker routine maintenance actions.

The circuit-interrupting device should not be confused with a motor-operated disconnect. The intent of this standard is to require maintenance intervals and activities on Protection Systems equipment, and not just all system isolating equipment.

It is necessary, however, to classify a device that actuates a high-speed auto-closing ground switch as an interrupting device, if this ground switch is utilized in a Protection System and forces a ground Fault to occur that then results in an expected Protection System operation to clear the forced ground Fault. The SDT believes that this is essentially a transferred-tripping device without the use of communications equipment. If this high-speed ground switch is "…designed to provide protection for the BES…" then this device needs to be treated as any other Protection System component. The control circuitry would have to be tested within 12 years, and any electromechanically operated device will have to be tested every six years. If the spring-operated ground switch can be disconnected from the solenoid triggering unit, then the solenoid triggering unit can easily be tested without the actual closing of the ground blade.

The dc control circuitry also includes each auxiliary tripping relay (94) and each lock-out relay (86) that may exist in any particular trip scheme. If the lock-out relays (86) are electromechanical type components, then they must be trip tested. The PSMT SDT considers these components to share some similarities in failure modes as electromechanical protective relays; as such, there is a six-year maximum interval between mandated maintenance tasks unless PBM is applied.

Contacts of the 86 and/or 94 that pass the trip current on to the circuit interrupting device trip coils will have to be checked as part of the 12 year requirement. Contacts of the 86 and/or 94 lock relay that operate non-BES interrupting devices are not required. Normally-open contacts that are not used to pass a trip signal and normally-closed contacts do not have to be verified. Verification of the tripping paths is the requirement.

New technology is also accommodated here; there are some tripping systems that have replaced the traditional hard-wired trip circuitry with other methods of trip-signal conveyance such as fiber-optics. It is the intent of the PSMT SDT to include this, and any other, technology that is used to convey a trip signal from a protective relay to a circuit breaker (or other interrupting device) within this category of equipment. The requirement for these systems is verification of the tripping path.

Monitoring of the control circuit integrity allows for no maintenance activity on the control circuit (excluding the requirement to operate trip coils and electromechanical lockout and/or tripping auxiliary relays). Monitoring of integrity means to monitor for continuity and/or presence of voltage on each trip path. For Ethernet or fiber-optic control systems, monitoring of integrity means to monitor communication ability between the relay and the circuit breaker.

15.3.1 Frequently Asked Questions:

Is it permissible to verify circuit breaker tripping at a different time (and interval) than when we verify the protective relays and the instrument transformers?

Yes, provided the entire Protective System is tested within the individual component's maximum allowable testing intervals.

The Protection System Maintenance Standard describes requirements for verifying the tripping of circuit breakers. What is this telling me about maintenance of circuit breakers?

Requirements in PRC-005-X are intended to verify the integrity of tripping circuits, including the breaker trip coil, as well as the presence of auxiliary supply (usually a battery) for energizing the trip coil if a protection function operates. Beyond this, PRC-005-X sets no requirements for verifying circuit breaker performance, or for maintenance of the circuit breaker.

How do I test each dc Control Circuit trip path, as established in Table 1-5 "Protection System Control Circuitry (Trip coils and auxiliary relays)"?

Table 1-5 specifies that each breaker trip coil and lockout relays that carry trip current to a trip coil must be operated within the specified time period. The required operations may be via targeted maintenance activities, or by documented operation of these devices for other purposes such as Fault clearing.

Are high-speed ground switch trip coils included in the dc control circuitry?

Yes. PRC-005-X includes high-speed grounding switch trip coils within the dc control circuitry to the degree that the initiating Protection Systems are characterized as "transmission Protection Systems."

Does the control circuitry and trip coil of a non-BES breaker, tripped via a BES protection component, have to be tested per Table 1.5? (Refer to Table 3 for examples 1 and 2) Example 1: A non-BES circuit breaker that is tripped via a Protection System to which PRC-005-X applies might be (but is not limited to) a 12.5KV circuit breaker feeding (non-black-start) radial Loads but has a trip that originates from an under-frequency (81) relay.

- The relay must be verified.
- The voltage signal to the relay must be verified.
- All of the relevant dc supply tests still apply.
- The unmonitored trip circuit between the relay and any lock-out or auxiliary relay must be verified every 12 years.
- The unmonitored trip circuit between the lock-out (or auxiliary relay) and the non-BES breaker does not have to be proven with an electrical trip.
- In the case where there is no lock-out or auxiliary tripping relay used, the trip circuit to the non-BES breaker does not have to be proven with an electrical trip.
- The trip coil of the non-BES circuit breaker does not have to be individually proven with an electrical trip.

Example 2: A Transmission Owner may have a non-BES breaker that is tripped via a Protection System to which PRC-005-X applies, which may be (but is not limited to) a 13.8 KV circuit breaker feeding (non-black-start) radial Loads but has a trip that originates from a BES 115KV line relay.

- The relay must be verified
- The voltage signal to the relay must be verified

- All of the relevant dc supply tests still apply
- The unmonitored trip circuit between the relay and any lock-out (86) or auxiliary (94) relay must be verified every 12 years
- The unmonitored trip circuit between the lock-out (86) (or auxiliary (94)) relay and the non-BES breaker does not have to be proven with an electrical trip
- In the case where there is no lockout (86) or auxiliary (94) tripping relay used, the trip circuit to the non-BES breaker does not have to be proven with an electrical trip.
- The trip coil of the non-BES circuit breaker does not have to be individually proven with an electrical trip

Example 3: A Generator Owner may have a non-BES circuit breaker that is tripped via a Protection System to which PRC-005-X applies, such as the generator field breaker and low-side breakers on station service/excitation transformers connected to the generator bus.

Trip testing of the generator field breaker and low side station service/excitation transformer breaker(s) via lockout or auxiliary tripping relays are not required since these breakers may be associated with radially fed loads and are not considered to be BES breakers. An example of an otherwise non-BES circuit breaker that is tripped via a BES protection component might be (but is not limited to) a 6.9kV station service transformer source circuit breaker but has a trip that originates from a generator differential (87) relay.

- The differential relay must be verified.
- The current signals to the relay must be verified.
- All of the relevant dc supply tests still apply.
- The unmonitored trip circuit between the relay and any lock-out or auxiliary relay must be verified every 12 years.
- The unmonitored trip circuit between the lock-out (or auxiliary relay) and the non-BES breaker does not have to be proven with an electrical trip.
- In the case where there is no lock-out or auxiliary tripping relay used, the trip circuit to the non-BES breaker does not have to be proven with an electrical trip.
- The trip coil of the non-BES circuit breaker does not have to be individually proven with an electrical trip.

However, it is very prudent to verify the tripping of such breakers for the integrity of the overall generation plant.

Do I have to verify operation of breaker "a" contacts or any other normally closed auxiliary contacts in the trip path of each breaker as part of my control circuit test?

Operation of normally-closed contacts does not have to be verified. Verification of the tripping paths is the requirement. The continuity of the normally closed contacts will be verified when the tripping path is verified.

15.4 Batteries and DC Supplies (Table 1-4)

The NERC definition of a Protection System is:

- Protective relays which respond to electrical quantities,

- Communications Systems necessary for correct operation of protective functions,
- Voltage and current sensing devices providing inputs to protective relays,
- Station dc supply associated with protective functions (including station batteries, battery chargers, and non-battery-based dc supply), and
- Control circuitry associated with protective functions through the trip coil(s) of the circuit breakers or other interrupting devices.

The station battery is not the only component that provides dc power to a Protection System. In the new definition for Protection System, “station batteries” are replaced with “station dc supply” to make the battery charger and dc producing stored energy devices (that are not a battery) part of the Protection System that must be maintained.

The PSMT SDT recognizes that there are several technological advances in equipment and testing procedures that allow the owner to choose how to verify that a battery string is free of open circuits. The term “continuity” was introduced into the standard to allow the owner to choose how to verify continuity of a battery set by various methods, and not to limit the owner to other conventional methods of showing continuity. Continuity, as used in Table 1-4 of the standard, refers to verifying that there is a continuous current path from the positive terminal of the station battery set to the negative terminal. Without verifying continuity of a station battery, there is no way to determine that the station battery is available to supply dc power to the station. An open battery string will be an unavailable power source in the event of loss of the battery charger.

Batteries cannot be a unique population segment of a Performance-Based Maintenance Program (PBM) because there are too many variables in the electrochemical process to completely isolate all of the performance-changing criteria necessary for using PBM on battery Systems. However, nothing precludes the use of a PBM process for any other part of a dc supply besides the batteries themselves.

15.4.1 Frequently Asked Questions:

What constitutes the station dc supply, as mentioned in the definition of Protective System?

The previous definition of Protection System includes batteries, but leaves out chargers. The latest definition includes chargers, as well as dc systems that do not utilize batteries. This revision of PRC-005-X is intended to capture these devices that were not included under the previous definition. The station direct current (dc) supply normally consists of two components: the battery charger and the station battery itself. There are also emerging technologies that provide a source of dc supply that does not include either a battery or charger.

Battery Charger - The battery charger is supplied by an available ac source. At a minimum, the battery charger must be sized to charge the battery (after discharge) and supply the constant dc load. In many cases, it may be sized also to provide sufficient dc current to handle the higher energy requirements of tripping breakers and switches when actuated by the protective relays in the Protection System.

Station Battery - Station batteries provide the dc power required for tripping and for supplying normal dc power to the station in the event of loss of the battery charger. There are several technologies of battery that require unique forms of maintenance as established in Table 1-4.

Emerging Technologies - Station dc supplies are currently being developed that use other energy storage technologies besides the station battery to prevent loss of the station dc supply when ac power is lost. Maintenance of these station dc supplies will require different kinds of tests and inspections. Table 1-4 presents maintenance activities and maximum allowable testing intervals for these new station dc supply technologies. However, because these technologies are relatively new, the maintenance activities for these station dc supplies may change over time.

What did the PSMT SDT mean by "continuity" of the dc supply?

The PSMT SDT recognizes that there are several technological advances in equipment and testing procedures that allow the owner to choose how to verify that a battery string is free of open circuits. The term "continuity" was introduced into the standard to allow the owner to choose how to verify continuity (no open circuits) of a battery set by various methods, and not to limit the owner to other conventional methods of showing continuity – lack of an open circuit. Continuity, as used in Table 1-4 of the standard, refers to verifying that there is a continuous current path from the positive terminal of the station battery set to the negative terminal (no open circuit). Without verifying continuity of a station battery, there is no way to determine that the station battery is available to supply dc power to the station. Whether it is caused from an open cell or a bad external connection, an open battery string will be an unavailable power source in the event of loss of the battery charger.

The current path through a station battery from its positive to its negative connection to the dc control circuits is composed of two types of elements. These path elements are the electrochemical path through each of its cells and all of the internal and external metallic connections and terminations of the batteries in the battery set. If there is loss of continuity (an open circuit) in any part of the electrochemical or metallic path, the battery set will not be available for service. In the event of the loss of the ac source or battery charger, the battery must be capable of supplying dc current, both for continuous dc loads and for tripping breakers and switches. Without continuity, the battery cannot perform this function.

At generating stations and large transmission stations where battery chargers are capable of handling the maximum current required by the Protection System, there are still problems that could potentially occur when the continuity through the connected battery is interrupted.

- Many battery chargers produce harmonics which can cause failure of dc power supplies in microprocessor-based protective relays and other electronic devices connected to station dc supply. In these cases, the substation battery serves as a filter for these harmonics. With the loss of continuity in the battery, the filter provided by the battery is no longer present.

- Loss of electrical continuity of the station battery will cause, in most battery chargers, regardless of the battery charger's output current capability, a delayed response in full output current from the charger. Almost all chargers have an intentional one- to two-second delay to switch from a low substation dc load current to the maximum output of the charger. This delay would cause the opening of circuit breakers to be delayed, which could violate system performance standards.

Monitoring of the station dc supply voltage will not indicate that there is a problem with the dc current path through the battery, unless the battery charger is taken out of service. At that time, a break in the continuity of the station battery current path will be revealed because there will be no voltage on the station dc circuitry. This particular test method, while proving battery continuity, may not be acceptable to all installations.

Although the standard prescribes what must be accomplished during the maintenance activity, it does not prescribe how the maintenance activity should be accomplished. There are several methods that can be used to verify the electrical continuity of the battery. These are not the only possible methods, simply a sampling of some methods:

- One method is to measure that there is current flowing through the battery itself by a simple clamp on milliamp-range ammeter. A battery is always either charging or discharging. Even when a battery is charged, there is still a measurable float charge current that can be detected to verify that there is continuity in the electrical path through the battery.
- A simple test for continuity is to remove the battery charger from service and verify that the battery provides voltage and current to the dc system. However, the behavior of the various dc-supplied equipment in the station should be considered before using this approach.
- Manufacturers of microprocessor-controlled battery chargers have developed methods for their equipment to periodically (or continuously) test for battery continuity. For example, one manufacturer periodically reduces the float voltage on the battery until current from the battery to the dc load can be measured to confirm continuity.
- Applying test current (as in some ohmic testing devices, or devices for locating dc grounds) will provide a current that when measured elsewhere in the string, will prove that the circuit is continuous.
- Internal ohmic measurements of the cells and units of lead-acid batteries (VRLA & VLA) can detect lack of continuity within the cells of a battery string; and when used in conjunction with resistance measurements of the battery's external connections, can prove continuity. Also some methods of taking internal ohmic measurements, by their very nature, can prove the continuity of a battery string without having to use the results of resistance measurements of the external connections.
- Specific gravity tests could infer continuity because without continuity there could be no charging occurring; and if there is no charging, then specific gravity will go down below acceptable levels over time.

No matter how the electrical continuity of a battery set is verified, it is a necessary maintenance activity that must be performed at the intervals prescribed by Table 1-4 to insure that the station dc supply has a path that can provide the required current to the Protection System at all times.

When should I check the station batteries to see if they have sufficient energy to perform as manufactured?

The answer to this question depends on the type of battery (valve-regulated lead-acid, vented lead-acid, or nickel-cadmium) and the maintenance activity chosen.

For example, if you have a valve-regulated lead-acid (VRLA) station battery, and you have chosen to evaluate the measured cell/unit internal ohmic values to the battery cell's baseline, you will have to perform verification at a maximum maintenance interval of no greater than every six months. While this interval might seem to be quite short, keep in mind that the six-month interval is important for VRLA batteries; this interval provides an accumulation of data that better shows when a VRLA battery is incapable of performing as manufactured.

If, for a VRLA station battery, you choose to conduct a performance capacity test on the entire station battery as the maintenance activity, then you will have to perform verification at a maximum maintenance interval of no greater than every three calendar years.

How is a baseline established for cell/unit internal ohmic measurements?

Establishment of cell/unit internal ohmic baseline measurements should be completed when lead-acid batteries are newly installed. To ensure that the baseline ohmic cell/unit values are most indicative of the station battery's ability to perform as manufactured, they should be made at some point in time after the installation to allow the cell chemistry to stabilize after the initial freshening charge. An accepted industry practice for establishing baseline values is after six-months of installation, with the battery fully charged and in service. However, it is recommended that each owner, when establishing a baseline, should consult the battery manufacturer for specific instructions on establishing an ohmic baseline for their product, if available.

When internal ohmic measurements are taken, the same make/model test equipment should be used to establish the baseline and used for the future trending of the cells internal ohmic measurements because of variances in test equipment and the type of ohmic measurement used by different manufacturer's equipment. Keep in mind that one manufacturer's "Conductance" test equipment does not produce similar results as another manufacturer's "Conductance" test equipment, even though both manufacturers have produced "Ohmic" test equipment. Therefore, for meaningful results to an established baseline, the same make/model of instrument should be used.

For all new installations of valve-regulated lead-acid (VRLA) batteries and vented lead-acid (VLA) batteries, where trending of the cells internal ohmic measurements to a baseline are to be used to determine the ability of the station battery to perform as manufactured, the establishment of the baseline, as described above, should be followed at the time of installation to insure the most accurate trending of the cell/unit. However, often for older VRLA batteries, the owners of the station batteries have not established a baseline at installation. Also for owners of VLA batteries who want to establish a maintenance activity which requires trending of measured ohmic values to a baseline, there was typically no baseline established at installation of the station battery to trend to.

To resolve the problem of the unavailability of baseline internal ohmic measurements for the individual cell/unit of a station battery, many manufacturers of internal ohmic measurement devices have established libraries of baseline values for VRLA and VLA batteries using their testing device. Also, several of the battery manufacturers have libraries of baselines for their products that can be used to trend to. However, it is important that when using battery manufacturer-supplied data that it is verified that the baseline readings to be used were taken with the same ohmic testing device that will be used for future measurements (for example "Conductance Readings" from one manufacturer's test equipment do not correlate to "Impedance Readings" from a different manufacturer's test equipment). Although many manufacturers may have provided baseline values, which will allow trending of the internal ohmic measurements over the remaining life of a station battery, these baselines are not the actual cell/unit measurements for the battery being trended. It is important to have a baseline tailored to the station battery to more accurately use the tool of ohmic measurement trending. That more customized baseline can only be created by following the establishment of a baseline for each cell/unit at the time of installation of the station battery.

Why determine the State of Charge?

Even though there is no present requirement to check the state of charge of a battery, it can be a very useful tool in determining the overall condition of a battery system. The following discussions are offered as a general reference.

When a battery is fully charged, the battery is available to deliver its existing capacity. As a battery is discharged, its ability to deliver its maximum available capacity is diminished. It is necessary to determine if the state of charge has dropped to an unacceptable level.

What is State of Charge and how can it be determined in a station battery?

The state of charge of a battery refers to the ratio of residual capacity at a given instant to the maximum capacity available from the battery. When a battery is fully charged, the battery is available to deliver its existing capacity. As a battery is discharged, its ability to deliver its maximum available capacity is diminished. Knowing the amount of energy left in a battery compared with the energy it had when it was fully charged gives the user an indication of how much longer a battery will continue to perform before it needs recharging.

For vented lead-acid (VLA) batteries which use accessible liquid electrolyte, a hydrometer can be used to test the specific gravity of each cell as a measure of its state of charge. The hydrometer depends on measuring changes in the weight of the active chemicals. As the battery discharges, the active electrolyte, sulfuric acid, is consumed and the concentration of the sulfuric acid in water is reduced. This, in turn, reduces the specific gravity of the solution in direct proportion to the state of charge. The actual specific gravity of the electrolyte can, therefore, be used as an indication of the state of charge of the battery. Hydrometer readings may not tell the whole story, as it takes a while for the acid to get mixed up in the cells of a VLA battery. If measured right after charging, you might see high specific gravity readings at the top of the cell, even though it is much less at the bottom. Conversely, if taken shortly after adding water to the cell, the specific gravity readings near the top of the cell will be lower than those at the bottom.

Nickel-cadmium batteries, where the specific gravity of the electrolyte does not change during battery charge and discharge, and valve-regulated lead-acid (VRLA) batteries, where the electrolyte is not accessible, cannot have their state of charge determined by specific gravity readings. For these two types of batteries, and for VLA batteries also, where another method besides taking hydrometer readings is desired, the state of charge may be determined by taking voltage and current readings at the battery terminals. The methods employed to obtain accurate readings vary for the different battery types. Manufacturers' information and IEEE guidelines can be consulted for specifics; (see IEEE 1106 Annex B for Nickel Cadmium batteries, IEEE 1188 Annex A for VRLA batteries and IEEE 450 for VLA batteries.

Why determine the Connection Resistance?

High connection resistance can cause abnormal voltage drop or excessive heating during discharge of a station battery. During periods of a high rate of discharge of the station battery, a very high resistance can cause severe damage. The maintenance requirement to verify battery terminal connection resistance in Table 1-4 is established to verify that the integrity of all battery electrical connections is acceptable. This verification includes cell-to-cell (intercell) and external circuit terminations. Your method of checking for acceptable values of intercell and terminal connection resistance could be by individual readings, or a combination of the two. There are test methods presently that can read post termination resistances and resistance values between external posts. There are also test methods presently available that take a combination reading of the post termination connection resistance plus the intercell resistance value plus the post termination connection resistance value. Either of the two methods, or any other method, that can show if the adequacy of connections at the battery posts is acceptable.

Adequacy of the electrical terminations can be determined by comparing resistance measurements for all connections taken at the time of station battery's installation to the same resistance measurements taken at the maintenance interval chosen, not to exceed the maximum maintenance interval of Table 1-4. Trending of the interval measurements to the baseline measurements will identify any degradation in the battery connections. When the connection resistance values exceed the acceptance criteria for the connection, the connection is typically disassembled, cleaned, reassembled and measurements taken to verify that the measurements are adequate when compared to the baseline readings.

What conditions should be inspected for visible battery cells?

The maintenance requirement to inspect the cell condition of all station battery cells where the cells are visible is a maintenance requirement of Table 1-4. Station batteries are different from any other component in the Protection Station because they are a perishable product due to the electrochemical process which is used to produce dc electrical current and voltage. This inspection is a detailed visual inspection of the cells for abnormalities that occur in the aging process of the cell. In VLA battery visual inspections, some of the things that the inspector is typically looking for on the plates are signs of sulfation of the plates, abnormal colors (which are an indicator of sulfation or possible copper contamination) and abnormal conditions such as cracked grids. The visual inspection could look for symptoms of hydration that would indicate that the battery has been left in a completely discharged state for a prolonged period. Besides looking at the plates for signs of aging, all internal connections, such as the bus bar connection to each plate, and the connections to all posts of the battery need to be visually inspected for abnormalities. In a complete visual inspection for the condition of the cell the cell plates, separators and sediment space of each cell must be looked at for signs of deterioration. An inspection of the station battery's cell condition also includes looking at all terminal posts and cell-to-cell electric connections to ensure they are corrosion free. The case of the battery containing the cell, or cells, must be inspected for cracks and electrolyte leaks through cracks and the post seals.

This maintenance activity cannot be extended beyond the maximum maintenance interval of Table 1-4 by a Performance-Based Maintenance Program (PBM) because of the electrochemical aging process of the station battery, nor can there be any monitoring associated with it because there must be a visual inspection involved in the activity. A remote visual inspection could possibly be done, but its interval must be no greater than the maximum maintenance interval of Table 1-4.

Why is it necessary to verify the battery string can perform as manufactured? I only care that the battery can trip the breaker, which means that the battery can perform as designed. I oversize my batteries so that even if the battery cannot perform as manufactured, it can still trip my breakers.

The fundamental answer to this question revolves around the concept of battery performance “as designed” vs. battery performance “as manufactured.” The purpose of the various sections of Table 1-4 of this standard is to establish requirements for the Protection System owner to maintain the batteries, to ensure they will operate the equipment when there is an incident that requires dc power, and ensure the batteries will continue to provide adequate service until at least the next maintenance interval. To meet these goals, the correct battery has to be properly selected to meet the design parameters, and the battery has to deliver the power it was manufactured to provide.

When testing batteries, it may be difficult to determine the original design (i.e., load profile) of the dc system. This standard is not intended as a design document, and requirements relating to design are, therefore, not included.

Where the dc load profile is known, the best way to determine if the system will operate as designed is to conduct a service test on the battery. However, a service test alone might not fully determine if the battery is healthy. A battery with 50% capacity may be able to pass a service test, but the battery would be in a serious state of deterioration and could fail at some point in the near future.

To ensure that the battery will meet the required load profile and continue to meet the load profile until the next maintenance interval, the installed battery must be sized correctly (i.e., a correct design), and it must be in a good state of health. Since the design of the dc system is not within the scope of the standard, the only consistent and reliable method to ensure that the battery is in a good state of health is to confirm that it can perform as manufactured. If the battery can perform as manufactured and it has been designed properly, the system should operate properly until the next maintenance interval.

How do I verify the battery string can perform as manufactured?

Optimally, actual battery performance should be verified against the manufacturer’s rating curves. The best practice for evaluating battery performance is via a performance test. However, due to both logistical and system reliability concerns, some Protection System owners prefer other methods to determine if a battery can perform as manufactured. There are several battery parameters that can be evaluated to determine if a battery can perform as manufactured. Ohmic measurements and float current are two examples of parameters that have been reported to assist in determining if a battery string can perform as manufactured.

The evaluation of battery parameters in determining battery health is a complex issue, and is not an exact science. This standard gives the user an opportunity to utilize other measured parameters to determine if the battery can perform as manufactured. It is the responsibility of

the Protection System owner, however, to maintain a documented process that demonstrates the chosen parameter(s) and associated methodology used to determine if the battery string can perform as manufactured.

Whatever parameters are used to evaluate the battery (ohmic measurements, float current, float voltages, temperature, specific gravity, performance test, or combination thereof), the goal is to determine the value of the measurement (or the percentage change) at which the battery fails to perform as manufactured, or the point where the battery is deteriorating so rapidly that it will not perform as manufactured before the next maintenance interval.

This necessitates the need for establishing and documenting a baseline. A baseline may be required of every individual cell, a particular battery installation, or a specific make, model, or size of a cell. Given a consistent cell manufacturing process, it may be possible to establish a baseline number for the cell (make/model/type) and, therefore, a subsequent baseline for every installation would not be necessary. However, future installations of the same battery types should be spot-checked to ensure that your baseline remains applicable.

Consistent testing methods by trained personnel are essential. Moreover, it is essential that these technicians utilize the same make/model of ohmic test equipment each time readings are taken in order to establish a meaningful and accurate trend line against the established baseline. The type of probe and its location (post, connector, etc.) for the reading need to be the same for each subsequent test. The room temperature should be recorded with the readings for each test as well. Care should be taken to consider any factors that might lead a trending program to become invalid.

Float current along with other measureable parameters can be used in lieu of or in concert with ohmic measurement testing to measure the ability of a battery to perform as manufactured. The key to using any of these measurement parameters is to establish a baseline and the point where the reading indicates that the battery will not perform as manufactured.

The establishment of a baseline may be different for various types of cells and for different types of installations. In some cases, it may be possible to obtain a baseline number from the battery manufacturer, although it is much more likely that the baseline will have to be established after the installation is complete. To some degree, the battery may still be “forming” after installation; consequently, determining a stable baseline may not be possible until several months after the battery has been in service.

The most important part of this process is to determine the point where the ohmic reading (or other measured parameter(s)) indicates that the battery cannot perform as manufactured. That point could be an absolute number, an absolute change, or a percentage change of an established baseline.

Since there are no universally-accepted repositories of this information, the Protection System owner will have to determine the value/percentage where the battery cannot perform as manufactured (heretofore referred to as a failed cell). This is the most difficult and important part of the entire process.

To determine the point where the battery fails to perform as manufactured, it is helpful to have a history of a battery type, if the data includes the parameter(s) used to evaluate the battery's ability to perform as manufactured against the actual demonstrated performance/capacity of a battery/cell.

For example, when an ohmic reading has been recorded that the user suspects is indicating a failed cell, a performance test of that cell (or string) should be conducted in order to prove/quantify that the cell has failed. Through this process, the user needs to determine the ohmic value at which the performance of the cell has dropped below 80% of the manufactured, rated performance. It is likely that there may be a variation in ohmic readings that indicates a failed cell (possibly significant). It is prudent to use the most conservative values to determine the point at which the cell should be marked for replacement. Periodically, the user should demonstrate that an “adequate” ohmic reading equates to an adequate battery performance (>80% of capacity).

Similarly, acceptance criteria for "good" and "failed" cells should be established for other parameters such as float current, specific gravity, etc., if used to determine the ability of a battery to function as designed.

What happens if I change the make/model of ohmic test equipment after the battery has been installed for a period of time?

If a user decides to switch testers, either voluntarily or because the equipment is not supported/sold any longer, the user may have to establish a new base line and new parameters that indicate when the battery no longer performs as manufactured. The user always has a choice to perform a capacity test in lieu of establishing new parameters.

What are some of the differences between lead-acid and nickel-cadmium batteries?

There is a marked difference in the aging process of lead acid and nickel-cadmium station batteries. The difference in the aging process of these two types of batteries is chiefly due to the electrochemical process of the battery type. Aging and eventual failure of lead acid batteries is due to expansion and corrosion of the positive grid structure, loss of positive plate active material, and loss of capacity caused by physical changes in the active material of the positive plates. In contrast, the primary failure of nickel-cadmium batteries is due to the gradual linear aging of the active materials in the plates. The electrolyte of a nickel-cadmium battery only facilitates the chemical reaction (it functions only to transfer ions between the positive and negative plates), but is not chemically altered during the process like the electrolyte of a lead acid battery. A lead acid battery experiences continued corrosion of the positive plate and grid structure throughout its operational life while a nickel-cadmium battery does not.

Changes to the properties of a lead acid battery when periodically measured and trended to a baseline, can indicate aging of the grid structure, positive plate deterioration, or changes in the active materials in the plate.

Because of the clear differences in the aging process of lead acid and nickel-cadmium batteries, there are no significantly measurable properties of the nickel-cadmium battery that can be measured at a periodic interval and trended to determine aging. For this reason, Table 1-4(c) (Protection System Station dc supply Using nickel-cadmium [NiCad] Batteries) only specifies one minimum maintenance activity and associated maximum maintenance interval necessary to verify that the station battery can perform as manufactured by evaluating cell/unit measurements indicative of battery performance against the station battery baseline. This maintenance activity is to conduct a performance or modified performance capacity test of the entire battery bank.

Why in Table 1-4 of PRC-005-X is there a maintenance activity to inspect the structural intergrity of the battery rack?

The purpose of this inspection is to verify that the battery rack is correctly installed and has no deterioration that could weaken its structural integrity.

Because the battery rack is specifically manufactured for the battery that is mounted on it, weakening of its structural members by rust or corrosion can physically jeopardize the battery.

What is required to comply with the "Unintentional dc Grounds" requirement?

In most cases, the first ground that appears on a battery is not a problem. It is the unintentional ground that appears on the opposite pole that becomes problematic. Even then many systems are designed to operate favorably under some unintentional DC ground situations. It is up to the owner of the Protection System to determine if corrective actions are needed on detected unintentional DC grounds. The standard merely requires that a check be made for the existence of Unintentional DC Grounds. Obviously, a "check-off" of some sort will have to be devised by the inspecting entity to document that a check is routinely done for Unintentional DC Grounds because of the possible consequences to the Protection System.

Where the standard refers to "all cells," is it sufficient to have a documentation method that refers to "all cells," or do we need to have separate documentation for every cell? For example, do I need 60 individual documented check-offs for good electrolyte level, or would a single check-off per bank be sufficient?

A single check-off per battery bank is sufficient for documentation, as long as the single check-off attests to checking all cells/units.

Does this standard refer to Station batteries or all batteries; for example, Communications Site Batteries?

This standard refers to Station Batteries. The drafting team does not believe that the scope of this standard refers to communications sites. The batteries covered under PRC-005-X are the batteries that supply the trip current to the trip coils of the interrupting devices that are a part of the Protection System. The SDT believes that a loss of power to the communications systems at a remote site would cause the communications systems associated with protective relays to alarm at the substation. At this point, the corrective actions can be initiated.

What are cell/unit internal ohmic measurements?

With the introduction of Valve-Regulated Lead-Acid (VRLA) batteries to station dc supplies in the 1980's several of the standard maintenance tools that are used on Vented Lead-Acid (VLA) batteries were unable to be used on this new type of lead-acid battery to determine its state of health. The only tools that were available to give indication of the health of these new VRLA batteries were voltage readings of the total battery voltage, the voltage of the individual cells and periodic discharge tests.

In the search for a tool for determining the health of a VRLA battery several manufacturers studied the electrical model of a lead acid battery's current path through its cell. The overall battery current path consists of resistance and inductive and capacitive reactance. The inductive reactance in the current path through the battery is so minuscule when compared to the huge capacitive reactance of the cells that it is often ignored in most circuit models of the battery cell. Taking the basic model of a battery cell manufacturers of battery test equipment have developed and marketed testing devices to take measurements of the current path to detect degradation in the internal path through the cell.

In the battery industry, these various types of measurements are referred to as ohmic measurements. Terms used by the industry to describe ohmic measurements are ac conductance, ac impedance, and dc resistance. They are defined by the test equipment providers and IEEE and refer to the method of taking ohmic measurements of a lead acid battery. For example, in one manufacturer's ac conductance equipment measurements are taken by applying a voltage of a known frequency and amplitude across a cell or battery unit and observing the ac current flow it produces in response to the voltage. A manufacturer of an ac impedance meter measures ac current of a known frequency and amplitude that is passed through the whole battery string and determines the impedances of each cell or unit by measuring the resultant ac voltage drop across them. On the other hand, dc resistance of a cell is measured by a third manufacturer's equipment by applying a dc load across the cell or unit and measuring the step change in both the voltage and current to calculate the internal dc resistance of the cell or unit.

It is important to note that because of the rapid development of the market for ohmic measurement devices, there were no standards developed or used to mandate the test signals used in making ohmic measurements. Manufacturers using proprietary methods and applying different frequencies and magnitudes for their signals have developed a diversity of measurement devices. This diversity in test signals coupled with the three different types of ohmic measurements techniques (impedance conductance and resistance) make it impossible to always get the same ohmic measurement for a cell with different ohmic measurement devices. However, IEEE has recognized the great value for choosing one device for ohmic measurement, no matter who makes it or the method to calculate the ohmic measurement. The only caution given by IEEE and the battery manufacturers is that when trending the cells of a lead acid station battery consistent ohmic measurement devices should be used to establish the baseline measurement and to trend the battery set for its entire life.

For VRLA batteries both IEEE Standard 1188 (Maintenance, Testing and Replacement of VRLA Batteries) and IEEE Standard 1187 (Installation Design and Installation of VRLA Batteries) recognize the importance of the maintenance activity of establishing a baseline for "cell/unit internal ohmic measurements (impedance, conductance and resistance)" and trending them at frequent intervals over the life of the battery. There are extensive discussions about the need for taking these measurements in these standards. IEEE Standard 1188 requires taking internal ohmic values as described in Annex C4 during regular inspections of the station battery. For VRLA batteries IEEE Standard 1188 in talking about the necessity of establishing a baseline and trending it over time says, "…depending on the degree of change a performance test, cell replacement or other corrective action may be necessary…" (IEEE std 1188-2005, C.4 page 18).

For VLA batteries IEEE Standard 484 (Installation of VLA batteries) gives several guidelines about establishing baseline measurements on newly installed lead acid stationary batteries. The standard also discusses the need to look for significant changes in the ohmic measurements, the caution that measurement data will differ with each type of model of instrument used, and lists a number of factors that affect ohmic measurements.

At the beginning of the 21st century, EPRI conducted a series of extensive studies to determine the relationship of internal ohmic measurements to the capacity of a lead acid battery cell. The studies indicated that internal ohmic measurements were in fact a good indicator of a lead acid battery cell's capacity, but because users often were only interested in the total station battery capacity and the technology does not precisely predict overall battery capacity, if a user only needs "an accurate measure of the overall battery capacity," they should "perform a battery capacity test."

Prior to the EPRI studies some large and small companies which owned and maintained station dc supplies in NERC Protection Systems developed maintenance programs where trending of ohmic measurements of cells/units of the station's battery became the maintenance activity for determining if the station battery could perform as manufactured. By evaluation of the trending of the ohmic measurements over time, the owner could track the performance of the individual components of the station battery and determine if a total station battery or components of it required capacity testing, removal, replacement or in many instances replacement of the entire station battery. By taking this condition based approach these owners have eliminated having to perform capacity testing at prescribed intervals to determine if a battery needs to be replaced and are still able to effectively determine if a station battery can perform as manufactured.

My VRLA batteries have multiple-cells within an individual battery jar (or unit); how am I expected to comply with the cell-to-cell ohmic measurement requirements on these units that I cannot get to?

Measurement of cell/unit (not all batteries allow access to "individual cells" some "units" or jars may have multiple cells within a jar) internal ohmic values of all types of lead acid batteries where the cells of the battery are not visible is a station dc supply maintenance activity in Table 1-4. In cases where individual cells in a multi-cell unit are inaccessible, an ohmic measurement of the entire unit may be made.

I have a concern about my batteries being used to support additional auxiliary loads beyond my protection control systems in a generation station. Is ohmic measurement testing sufficient for my needs?

While this standard is focused on addressing requirements for Protection Systems, if batteries are used to service other load requirements beyond that of Protection Systems (e.g. pumps, valves, inverter loads), the functional entity may consider additional testing to confirm that the capacity of the battery is sufficient to support all loads.

Why verify voltage?

There are two required maintenance activities associated with verification of dc voltages in Table 1-4. These two required activities are to verify station dc supply voltage and float voltage of the battery charger, and have different maximum maintenance intervals. Both of these voltage verification requirements relate directly to the battery charger maintenance.

The verification of the dc supply voltage is simply an observation of battery voltage to prove that the charger has not been lost or is not malfunctioning; a reading taken from the battery charger panel meter or even SCADA values of the dc voltage could be some of the ways that one could satisfy the requirements. Low battery voltage below float voltage indicates that the battery may be on discharge and, if not corrected, the station battery could discharge down to some extremely low value that will not operate the Protection System. High voltage, close to or above the maximum allowable dc voltage for equipment connected to the station dc supply indicates the battery charger may be malfunctioning by producing high dc voltage levels on the Protection System. If corrective actions are not taken to bring the high voltage down, the dc power supplies and other electronic devices connected to the station dc supply may be damaged. The maintenance activity of verifying the float voltage of the battery charger is not to prove that a charger is lost or producing high voltages on the station dc supply, but rather to prove that the charger is properly floating the battery within the proper voltage limits. As above, there are many ways that this requirement can be met.

Why check for the electrolyte level?

In vented lead-acid (VLA) and nickel-cadmium (NiCad) batteries the visible electrolyte level must be checked as one of the required maintenance activities that must be performed at an interval that is equal to or less than the maximum maintenance interval of Table 1-4. Because the electrolyte level in valve-regulated lead-acid (VRLA) batteries cannot be observed, there is no maintenance activity listed in Table 1-4 of the standard for checking the electrolyte level. Low electrolyte level of any cell of a VLA or NiCad station battery is a condition requiring correction. Typically, the electrolyte level should be returned to an acceptable level for both types of batteries (VLA and NiCad) by adding distilled or other approved-quality water to the cell.

Often people confuse the interval for watering all cells required due to evaporation of the electrolyte in the station battery cells with the maximum maintenance interval required to check the electrolyte level. In many of the modern station batteries, the jar containing the electrolyte is so large with the band between the high and low electrolyte level so wide that normal evaporation which would require periodic watering of all cells takes several years to occur. However, because loss of electrolyte due to cracks in the jar, overcharging of the station battery, or other unforeseen events can cause rapid loss of electrolyte; the shorter maximum maintenance intervals for checking the electrolyte level are required. A low level of electrolyte in a VLA battery cell which exposes the tops of the plates can cause the exposed portion of the plates to accelerated sulfation resulting in loss of cell capacity. Also, in a VLA battery where the electrolyte level goes below the end of the cell withdrawal tube or filling funnel, gasses can exit the cell by the tube instead of the flame arrester and present an explosion hazard.

What are the parameters that can be evaluated in Tables 1-4(a) and 1-4(b)?

The most common parameter that is periodically trended and evaluated by industry today to verify that the station battery can perform as manufactured is internal ohmic cell/unit measurements.

In the mid-1990s, several large and small utilities began developing maintenance and testing programs for Protection System station batteries using a condition based maintenance approach of trending internal ohmic measurements to each station battery cell's baseline value. Battery owners use the data collected from this maintenance activity to determine (1) when a station battery requires a capacity test (instead of performing a capacity test on a predetermined, prescribed interval), (2) when an individual cell or battery unit should be replaced, or (3) based on the analysis of the trended data, if the station battery should be replaced without performing a capacity test.

Other examples of measurable parameters that can be periodically trended and evaluated for lead acid batteries are cell voltage, float current, connection resistance. However, periodically trending and evaluating cell/unit Ohmic measurements are the most common battery/cell parameters that are evaluated by industry to verify a lead acid battery string can perform as manufactured.

Why does it appear that there are two maintenance activities in Table 1-4(b) (for VRLA batteries) that appear to be the same activity and have the same maximum maintenance interval?

There are two different and distinct reasons for doing almost the same maintenance activity at the same interval for valve-regulated lead-acid (VRLA) batteries. The first similar activity for VRLA batteries (Table 1-4(b)) that has the same maximum maintenance interval is to "measure battery cell/unit internal ohmic values." Part of the reason for this activity is because the visual inspection of the cell condition is unavailable for VRLA batteries. Besides the requirement to measure the internal ohmic measurements of VRLA batteries to determine the internal health of the cell, the maximum maintenance interval for this activity is significantly shorter than the interval for vented lead-acid (VLA) due to some unique failure modes for VRLA batteries. Some of the potential problems that VRLA batteries are susceptible to that do not affect VLA batteries are thermal runaway, cell dry-out, and cell reversal when one cell has a very low capacity.

The other similar activity listed in Table 1-4(b) is "…verify that the station battery can perform as manufactured by evaluating the measured cell/unit measurements indicative of battery performance (e.g. internal ohmic values) against the station battery baseline." This activity allows an owner the option to choose between this activity with its much shorter maximum maintenance interval or the longer maximum maintenance interval for the maintenance activity to "Verify that the station battery can perform as manufactured by conducting a performance or modified performance capacity test of the entire battery bank."

For VRLA batteries, there are two drivers for internal ohmic readings. The first driver is for a means to trend battery life. Trending against the baseline of VRLA cells in a battery string is essential to determine the approximate state of health of the battery. Ohmic measurement testing may be used as the mechanism for measuring the battery cells. If all the cells in the string exhibit a consistent trend line and that trend line has not risen above a specific deviation (e.g. 30%) over baseline for impedance tests or below baseline for conductance tests, then a judgment can be made that the battery is still in a reasonably good state of health and able to 'perform as manufactured.' It is essential that the specific deviation mentioned above is based on data (test or otherwise) that correlates the ohmic readings for a specific battery/tester combination to the health of the battery. This is the intent of the "perform **as** manufactured six-month test" at Row 4 on Table 1-4b.

The second big driver is VRLA batteries tendency for thermal runaway. This is the intent of the "thermal runaway test" at Row 2 on Table 1-4b. In order to detect a cell in thermal runaway, you need not necessarily have a formal trending program. When a single cell/unit changes significantly or significantly varies from the other cells (e.g. a doubling of resistance/impedance or a 50% decrease in conductance), there is a high probability that the cell/unit/string needs to be replaced as soon as possible. In other words, if the battery is 10 years old and all the cells have approached a significant change in ohmic values over baseline, then you have a battery which is approaching end of life. You need to get ready to buy a new battery, but you do not have to worry about an impending catastrophic failure. On the other hand, if the battery is five years old and you have one cell that has a markedly different ohmic reading than all the other cells, then you need to be worried that this cell is susceptible to thermal runaway. If the float (charging) current has risen significantly and the ohmic measurement has increased/decreased as described above then concern of catastrophic failure should trigger attention for corrective action.

If an entity elects to use a capacity test rather than a cell ohmic value trending program, this does not eliminate the need to be concerned about thermal runaway – the entity still needs to do the six-month readings and look for cells which are outliers in the string but they need not trend results against the factory/as new baseline. Some entities will not mind the extra administrative burden of having the ongoing trending program against baseline - others would rather just do the capacity test and not have to trend the data against baseline. Nonetheless, all entities must look for ohmic outliers on a six-month basis.

It is possible to accomplish both tasks listed (trend testing for capability and testing for thermal runaway candidates) with the very same ohmic test. It becomes an analysis exercise of watching the trend from baselines and watching for the oblique cell measurement.

In table 1-4(f) (Exclusions for Protection System Station dc Supply Monitoring Devices and Systems), must all component attributes listed in the table be met before an exclusion can be granted for a maintenance activity?

Table 1-4(f) was created by the drafting team to allow Protection System dc supply owners to obtain exclusions from periodic maintenance activities by using monitoring devices. The basis of the exclusions granted in the table is that the monitoring devices must incorporate the monitoring capability of microprocessor based components which perform continuous self-monitoring. For failure of the microprocessor device used in dc supply monitoring, the self-checking routine in the microprocessor must generate an alarm which will be reported within 24 hours of device failure to a location where corrective action can be initiated.

Table 1-4(f) lists 8 component attributes along with a specific periodic maintenance activity associated with each of the 8 attributes listed. If an owner of a station dc supply wants to be excluded from periodically performing one of the 8 maintenance activities listed in table 1-4(f), the owner must have evidence that the monitoring and alarming component attributes associated with the excluded maintenance activity are met by the self-checking microprocessor based device with the specific component attribute listed in the table 1-4(f).

For example if an owner of a VLA station battery does not want to "verify station dc supply voltage" every "4 calendar months" (see table 1-4(a)), the owner can install a monitoring and alarming device "with high and low voltage monitoring and alarming of the battery charger voltage to detect charger overvoltage and charger failure" and "no periodic verification of station dc supply voltage is required" (see table 1-4(f) first row). However, if for the same Protection System discussed above, the owner does not install "electrolyte level monitoring and alarming in every cell" and "unintentional dc ground monitoring and alarming" (see second and third rows of table 1-4(f)), the owner will have to "inspect electrolyte level and for unintentional grounds" every "4 calendar months" (see table 1-4(a)).

15.5 Associated communications equipment (Table 1-2)

The equipment used for tripping in a communications-assisted trip scheme is a vital piece of the trip circuit. Remote action causing a local trip can be thought of as another parallel trip path to the trip coil that must be tested. Besides the trip output and wiring to the trip coil(s), there is also a communications medium that must be maintained. Newer technologies now exist that achieve communications-assisted tripping without the conventional wiring practices of older technology. For example, older technologies may have included Frequency Shift Key methods. This technology requires that guard and trip levels be maintained. The actual tripping path(s) to the trip coil(s) may be tested as a parallel trip path within the dc control circuitry tests. Emerging technologies transfer digital information over a variety of carrier mediums that are then interpreted locally as trip signals. The requirements apply to the communicated signal needed for the proper operation of the protective relay trip logic or scheme. Therefore, this standard is applied to equipment used to convey both trip signals (permissive or direct) and block signals.

It was the intent of this standard to require that a test be performed on any communications-assisted trip scheme, regardless of the vintage of technology. The essential element is that the tripping (or blocking) occurs locally when the remote action has been asserted; or that the tripping (or blocking) occurs remotely when the local action is asserted. Note that the required testing can still be done within the concept of testing by overlapping segments. Associated communications equipment can be (but is not limited to) testing at other times and different frequencies as the protective relays, the individual trip paths and the affected circuit interrupting devices.

Some newer installations utilize digital signals over fiber-optics from the protective relays in the control house to the circuit interrupting device in the yard. This method of tripping the circuit breaker, even though it might be considered communications, must be maintained per the dc control circuitry maintenance requirements.

15.5.1 Frequently Asked Questions:

What are some examples of mechanisms to check communications equipment functioning?

For unmonitored Protection Systems, various types of communications systems will have different facilities for on-site integrity checking to be performed at least every four months during a substation visit. Some examples are, but not limited to:

- On-off power-line carrier systems can be checked by performing a manual carrier keying test between the line terminals, or carrier check-back test from one terminal.
- Systems which use frequency-shift communications with a continuous guard signal (over a telephone circuit, analog microwave system, etc.) can be checked by observing for a loss-of-guard indication or alarm. For frequency-shift power-line carrier systems, the guard signal level meter can also be checked.
- Hard-wired pilot wire line Protection Systems typically have pilot-wire monitoring relays that give an alarm indication for a pilot wire ground or open pilot wire circuit loop.
- Digital communications systems typically have a data reception indicator or data error indicator (based on loss of signal, bit error rate, or frame error checking).

For monitored Protection Systems, various types of communications systems will have different facilities for monitoring the presence of the communications channel, and activating alarms that can be monitored remotely. Some examples are, but not limited to:

- On-off power-line carrier systems can be shown to be operational by automated periodic power-line carrier check-back tests with remote alarming of failures.
- Systems which use a frequency-shift communications with a continuous guard signal (over a telephone circuit, analog microwave system, etc.) can be remotely monitored with a loss-of-guard alarm or low signal level alarm.
- Hard-wired pilot wire line Protection Systems can be monitored by remote alarming of pilot-wire monitoring relays.
- Digital communications systems can activate remotely monitored alarms for data reception loss or data error indications.
- Systems can be queried for the data error rates.

For the highest degree of monitoring of Protection Systems, the communications system must monitor all aspects of the performance and quality of the channel that show it meets the design performance criteria, including monitoring of the channel interface to protective relays.

- In many communications systems signal quality measurements, including signal-to-noise ratio, received signal level, reflected transmitter power or standing wave ratio, propagation delay, and data error rates are compared to alarm limits. These alarms are connected for remote monitoring.
- Alarms for inadequate performance are remotely monitored at all times, and the alarm communications system to the remote monitoring site must itself be continuously

monitored to assure that the actual alarm status at the communications equipment location is continuously being reflected at the remote monitoring site.

What is needed for the four-month inspection of communications-assisted trip scheme equipment?

The four-month inspection applies to unmonitored equipment. An example of compliance with this requirement might be, but is not limited to:

With each site visit, check that the equipment is free from alarms; check any metered signal levels, and that power is still applied. While this might be explicit for a particular type of equipment (i.e., FSK equipment), the concept should be that the entity verify that the communications equipment that is used in a Protection System is operable through a cursory inspection and site visit. This site visit can be eliminated on this particular example if the FSK equipment had a monitored alarm on Loss of Guard. Blocking carrier systems with auto checkbacks will present an alarm when the channel fails allowing a visual indication. With no auto checkback, the channel integrity will need to be verified by a manual checkback or a two ended signal check. This check could also be eliminated by bring the auto checkback failure alarm to the monitored central location.

Does a fiber optic I/O scheme used for breaker tripping or control within a station, for example - transmitting a trip signal or control logic between the control house and the breaker control cabinet, constitute a communications system?

This equipment is presently classified as being part of the Protection System control circuitry and tested per the portions of Table 1 applicable to "Protection System Control Circuitry", rather than those portions of the table applicable to communications equipment.

What is meant by "Channel" and "Communications Systems" in Table 1-2?

The transmission of logic or data from a relay in one station to a relay in another station for use in a pilot relay scheme will require a communications system of some sort. Typical relay communications systems use fiber optics, leased audio channels, power line carrier, and microwave. The overall communications system includes the channel and the associated communications equipment.

This standard refers to the "channel" as the medium between the transmitters and receivers in the relay panels such as a leased audio or digital communications circuit, power line and power line carrier auxiliary equipment, and fiber. The dividing line between the channel and the associated communications equipment is different for each type of media.

Examples of the Channel:

- Power Line Carrier (PLC) - The PLC channel starts and ends at the PLC transmitter and receiver output unless there is an internal hybrid. The channel includes the external hybrids, tuners, wave traps and the power line itself.
- Microwave –The channel includes the microwave multiplexers, radios, antennae and associated auxiliary equipment. The audio tone and digital transmitters and receivers in the relay panel are the associated communications equipment.
- Digital/Audio Circuit – The channel includes the equipment within and between the substations. The associated communications equipment includes the relay panel transmitters and receivers and the interface equipment in the relays.

- Fiber Optic – The channel starts at the fiber optic connectors on the fiber distribution panel at the local station and goes to the fiber optic distribution panel at the remote substation. The jumpers that connect the relaying equipment to the fiber distribution panel and any optical-electrical signal format converters are the associated communications equipment

Figure 1-2, A-1 and A-2 at the end of this document show good examples of the communications channel and the associated communications equipment.

In Table 1-2, the Maintenance Activities section of the Protection System Communications Equipment and Channels refers to the quality of the channel meeting "performance criteria." What is meant by performance criteria?

Protection System communications channels must have a means of determining if the channel and communications equipment is operating normally. If the channel is not operating normally, an alarm will be indicated. For unmonitored systems, this alarm will probably be on the panel. For monitored systems, the alarm will be transmitted to a remote location.

Each entity will have established a nominal performance level for each Protection System communications channel that is consistent with proper functioning of the Protection System. If that level of nominal performance is not being met, the system will go into alarm. Following are some examples of Protection System communications channel performance measuring:

- For direct transfer trip using a frequency shift power line carrier channel, a guard level monitor is part of the equipment. A normal receive level is established when the system is calibrated and if the signal level drops below an established level, the system will indicate an alarm.

- An on-off blocking signal over power line carrier is used for directional comparison blocking schemes on transmission lines. During a Fault, block logic is sent to the remote relays by turning on a local transmitter and sending the signal over the power line to a receiver at the remote end. This signal is normally off so continuous levels cannot be checked. These schemes use check-back testing to determine channel performance. A predetermined signal sequence is sent to the remote end and the remote end decodes this signal and sends a signal sequence back. If the sending end receives the correct information from the remote terminal, the test passes and no alarm is indicated. Full power and reduced power tests are typically run. Power levels for these tests are determined at the time of calibration.

- Pilot wire relay systems use a hardwire communications circuit to communicate between the local and remote ends of the protective zone. This circuit is monitored by circulating a dc current between the relay systems. A typical level may be 1 mA. If the level drops below the setting of the alarm monitor, the system will indicate an alarm.

- Modern digital relay systems use data communications to transmit relay information to the remote end relays. An example of this is a line current differential scheme commonly used on transmission lines. The protective relays communicate current magnitude and phase information over the communications path to determine if the

Fault is located in the protective zone. Quantities such as digital packet loss, bit error rate and channel delay are monitored to determine the quality of the channel. These limits are determined and set during relay commissioning. Once set, any channel quality problems that fall outside the set levels will indicate an alarm.

The previous examples show how some protective relay communications channels can be monitored and how the channel performance can be compared to performance criteria established by the entity. This standard does not state what the performance criteria will be; it just requires that the entity establish nominal criteria so Protection System channel monitoring can be performed.

How is the performance criteria of Protection System communications equipment involved in the maintenance program?

An entity determines the acceptable performance criteria, depending on the technology implemented. If the communications channel performance of a Protection System varies from the pre-determined performance criteria for that system, then these results should be investigated and resolved.

How do I verify the A/D converters of microprocessor-based relays?

There are a variety of ways to do this. Two examples would be: using values gathered via data communications and automatically comparing these values with values from other sources, or using groupings of other measurements (such as vector summation of bus feeder currents) for comparison. Many other methods are possible.

15.6 Alarms (Table 2)

In addition to the tables of maintenance for the components of a Protection System, there is an additional table added for alarms. This additional table was added for clarity. This enabled the common alarm attributes to be consolidated into a single spot, and, thus, make it easier to read the Tables 1-1 through 1-5, Table 3, and Table 4. The alarms need to arrive at a site wherein a corrective action can be initiated. This could be a control room, operations center, etc. The alarming mechanism can be a standard alarming system or an auto-polling system; the only requirement is that the alarm be brought to the action-site within 24 hours. This effectively makes manned-stations equivalent to monitored stations. The alarm of a monitored point (for example a monitored trip path with a lamp) in a manned-station now makes that monitored point eligible for monitored status. Obviously, these same rules apply to a non-manned-station, which is that if the monitored point has an alarm that is auto-reported to the operations center (for example) within 24 hours, then it too is considered monitored.

15.6.1 Frequently Asked Questions:

Why are there activities defined for varying degrees of monitoring a Protection System component when that level of technology may not yet be available?

There may already be some equipment available that is capable of meeting the highest levels of monitoring criteria listed in the Tables. However, even if there is no equipment available today that can meet this level of monitoring the standard establishes the necessary requirements for when such equipment becomes available. By creating a roadmap for development, this provision makes the standard technology neutral. The Standard Drafting Team wants to avoid the need to revise the standard in a few years to accommodate technology advances that may be coming to the industry.

Does a fail-safe "form b" contact that is alarmed to a 24/7 operation center classify as an alarm path with monitoring?

If the fail-safe "form-b" contact that is alarmed to a 24/7 operation center causes the alarm to activate for failure of any portion of the alarming path from the alarm origin to the 24/7 operations center, then this can be classified as an alarm path with monitoring.

15.7 Distributed UFLS and Distributed UVLS Systems (Table 3)

Distributed UFLS and distributed UVLS systems have their maintenance activities documented in Table 3 due to their distributed nature allowing reduced maintenance activities and extended maximum maintenance intervals. Relays have the same maintenance activities and intervals as Table 1-1. Voltage and current-sensing devices have the same maintenance activity and interval as Table 1-3. DC systems need only have their voltage read at the relay every 12 years. Control circuits have the following maintenance activities every 12 years:

- Verify the trip path between the relay and lock-out and/or auxiliary tripping device(s).
- Verify operation of any lock-out and/or auxiliary tripping device(s) used in the trip circuit.
- No verification of trip path required between the lock-out (and/or auxiliary tripping device) and the non-BES interrupting device.
- No verification of trip path required between the relay and trip coil for circuits that have no lock-out and/or auxiliary tripping device(s).
- No verification of trip coil required.

No maintenance activity is required for associated communication systems for distributed UFLS and distributed UVLS schemes.

Non-BES interrupting devices that participate in a distributed UFLS or distributed UVLS scheme are excluded from the tripping requirement, and part of the control circuit test requirement; however, the part of the trip path control circuitry between the Load-Shed relay and lock-out or auxiliary tripping relay must be tested at least once every 12 years. In the case where there is no lock-out or auxiliary tripping relay used in a distributed UFLS or UVLS scheme which is not part of the BES, there is no control circuit test requirement. There are many circuit interrupting devices in the distribution system that will be operating for any given under-frequency event that requires tripping for that event. A failure in the tripping action of a single distributed system circuit breaker (or non-BES equipment interruption device) will be far less significant than, for example, any single transmission Protection System failure, such as a failure of a bus differential lock-out relay. While many failures of these distributed system circuit breakers (or non-BES equipment interruption device) could add up to be significant, it is also believed that many circuit breakers are operated often on just Fault clearing duty; and, therefore, these circuit breakers are operated at least as frequently as any requirements that appear in this standard.

There are times when a Protection System component will be used on a BES device, as well as a non-BES device, such as a battery bank that serves both a BES circuit breaker and a non-BES interrupting device used for UFLS. In such a case, the battery bank (or other Protection System component) will be subject to the Tables of the standard because it is used for the BES.

15.7.1 Frequently Asked Questions:

The standard reaches further into the distribution system than we would like for UFLS and UVLS

While UFLS and UVLS equipment are located on the distribution network, their job is to protect the Bulk Electric System. This is not beyond the scope of NERC's 215 authority.

FPA section 215(a) definitions section defines bulk power system as: "(A) facilities and control Systems necessary for operating an interconnected electric energy transmission network (or any portion thereof)." That definition, then, is limited by a later statement which adds the term bulk power system "…does not include facilities used in the local distribution of electric energy." Also, Section 215 also covers users, owners, and operators of bulk power Facilities.

UFLS and UVLS (when the UVLS is installed to prevent system voltage collapse or voltage instability for BES reliability) are not "used in the local distribution of electric energy," despite their location on local distribution networks. Further, if UFLS/UVLS Facilities were not covered by the reliability standards, then in order to protect the integrity of the BES during under-frequency or under-voltage events, that Load would have to be shed at the Transmission bus to ensure the Load-generation balance and voltage stability is maintained on the BES.

15.8 Automatic Reclosing (Table 4)

Please see the document referenced in Section F of PRC-005-3, "Considerations for Maintenance and Testing of Autoreclosing Schemes — November 2012", for a discussion of Automatic Reclosing as addressed in PRC-005-3.

15.8.1 Frequently-asked Questions

Automatic Reclosing is a control, not a protective function; why then is Automatic Reclosing maintenance included in the Protection System Maintenance Program (PSMP)?

Automatic Reclosing is a control function. The standard's title 'Protection System and Automatic Reclosing Maintenance' clearly distinguishes (separates) the Automatic Reclosing from the Protection System. Automatic Reclosing is included in the PSMP because it is a more pragmatic approach as compared to creating a parallel and essentially identical 'Control System Maintenance Program' for the two Automatic Reclosing component types.

Our maintenance practice consists of initiating the Automatic Reclosing relay and confirming the breaker closes properly and the close signal is released. This practice verifies the control circuitry associated with Automatic Reclosing. Do you agree?"

The described task partially verifies the control circuit maintenance activity. To meet the control circuit maintenance activity, responsible entities need to verify, *upon initiation*, that the reclosing relay does not issue a *premature closing command*. As noted on page 12 of the SAMS/SPCS report, the concern being addressed within the standard is premature autoreclosing that has the potential to cause generating unit or plant instability. Reclosing applications have many variations, responsible entities will need to verify the applicability of associated supervision/conditional logic and the reclosing relay operation; then verify the conditional logic or that the reclosing relay performs in a manner that does not result in a *premature closing command* being issued.

Some examples of conditions which can result in a premature closing command are: an improper supervision or conditional logic input which provides a false state and allows the reclosing relay to issue an improper close command based on incorrect conditions (i.e. voltage supervision, equipment status, sync window verification); timers utilized for closing actuation or reclosing arming/disarming circuitry which could allow the reclosing relay to issue an improper close command; a reclosing relay output contact failure which could result in a made-up-close condition / failure-to-release condition.

Why was a close-in three phase fault present for twice the normal clearing time chosen for the Automatic Reclosing exclusion? It exceeds TPL requirements and ignores the breaker closing time in a trip-close-trip sequence, thus making the exclusion harder to attain.

This condition represents a situation where a close signal is issued with no time delay or with less time delay than is intended, such as if a reclosing contact is welded closed. This failure mode can result in a minimum trip-close-trip sequence with the two faults cleared in primary protection operating time, and the open time between faults equal to the breaker closing cycle time. The sequence for this failure mode results in system impact equivalent to a high-speed autoreclosing sequence with no delay added in the autoreclosing logic. It represents a failure mode which must be avoided because it exceeds TPL requirements.

Do we have to test the various breaker closing circuit interlocks and controls such as anti-pump?

These components are not specifically addressed within Table 4, and need not be individually tested. They are indirectly verified by performing the Automatic Reclosing control circuitry verification as established in Table 4.

For Automatic Reclosing that <u>is not</u> part of an SPS, do we have to close the circuit breaker periodically?

No. For this application, you need only to verify that the Automatic Reclosing, upon initiation, does not issue a premature closing command. This activity is concerned only with assuring that a premature close does not occur, and cause generating plant instability.

For Automatic Reclosing that <u>is</u> part of an SPS, do we have to close the circuit breaker periodically?

Yes. In this application, successful closing is a necessary portion of the SPS, and must be verified.

15.9 Sudden Pressure Relaying (Table 5)

Please see the document referenced in Section F of PRC-005-X, “Sudden Pressure Relays and Other Devices that Respond to Non-Electrical Quantities – December 2013”, for a discussion of Sudden Pressure Relaying as addressed in PRC-005-X.

15.9.1 Frequently Asked Questions:

How do I verify the pressure or flow sensing mechanism is operable?

Operate, or cause to operate the mechanism responding to the rapid-pressure rise. The standard does not specify how to perform the maintenance.

Why do I have to test the fault pressure relay every 6 years? Our experience is that these devices have no trouble operating as we have had our share of nuisance trips on through-faults.

The frequency of the testing is set to align with previously set maintenance intervals in PRC-005 and align with a survey of respondents as detailed in the previously noted NERC SPCS paper responding to FERC Order 758.

Sudden Pressure Relaying control circuitry is now specifically mentioned in the maintenance tables. Do we have to trip our circuit breaker specifically from the trip output of the sudden pressure relay?

No. Verification may be by breaker tripping, but may be verified in overlapping segments with the Protection System control circuitry.

Can we use Performance Based Maintenance for fault pressure relays?

Yes. Performance Based Maintenance is applicable to fault pressure relays.

15.10 Examples of Evidence of Compliance

To comply with the requirements of this standard, an entity will have to document and save evidence. The evidence can be of many different forms. The Standard Drafting Team recognizes that there are concurrent evidence requirements of other NERC standards that could, at times, fulfill evidence requirements of this standard.

15.10.1 Frequently Asked Questions:

What forms of evidence are acceptable?

Acceptable forms of evidence, as relevant for the requirement being documented include, but are not limited to:

- Process documents or plans
- Data (such as relay settings sheets, photos, SCADA, and test records)
- Database lists, records and/or screen shots that demonstrate compliance information
- Prints, diagrams and/or schematics
- Maintenance records
- Logs (operator, substation, and other types of log)
- Inspection forms
- Mail, memos, or email proving the required information was exchanged, coordinated, submitted or received
- Check-off forms (paper or electronic)
- Any record that demonstrates that the maintenance activity was known, accounted for, and/or performed.

If I replace a failed Protection System component with another component, what testing do I need to perform on the new component?

In order to reset the Table 1 maintenance interval for the replacement component, all relevant Table 1 activities for the component should be performed.

I have evidence to show compliance for PRC-016 ("Special Protection System Misoperation"). Can I also use it to show compliance for this Standard, PRC-005-X?

Maintaining evidence for operation of Special Protection Systems could concurrently be utilized as proof of the operation of the associated trip coil (provided one can be certain of the trip coil involved). Thus, the reporting requirements that one may have to do for the Misoperation of a Special Protection Scheme under PRC-016 could work for the activity tracking requirements under this PRC-005-X.

I maintain Disturbance records which show Protection System operations. Can I use these records to show compliance?

These records can be concurrently utilized as dc trip path verifications, to the degree that they demonstrate the proper function of that dc trip path.

I maintain test reports on some of my Protection System components. Can I use these test reports to show that I have verified a maintenance activity?

Yes.

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3. “Transmission Relay System Performance Comparison For 2000, 2001, 2002, 2003, 2004 and 2005,” Working Group I17 of Power System Relaying Committee of IEEE Power Engineering Society, May 2006.

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8. “Analysis And Guidelines For Testing Numerical Protection Schemes,” Final Report of CIGRE WG 34.10, August 2000.

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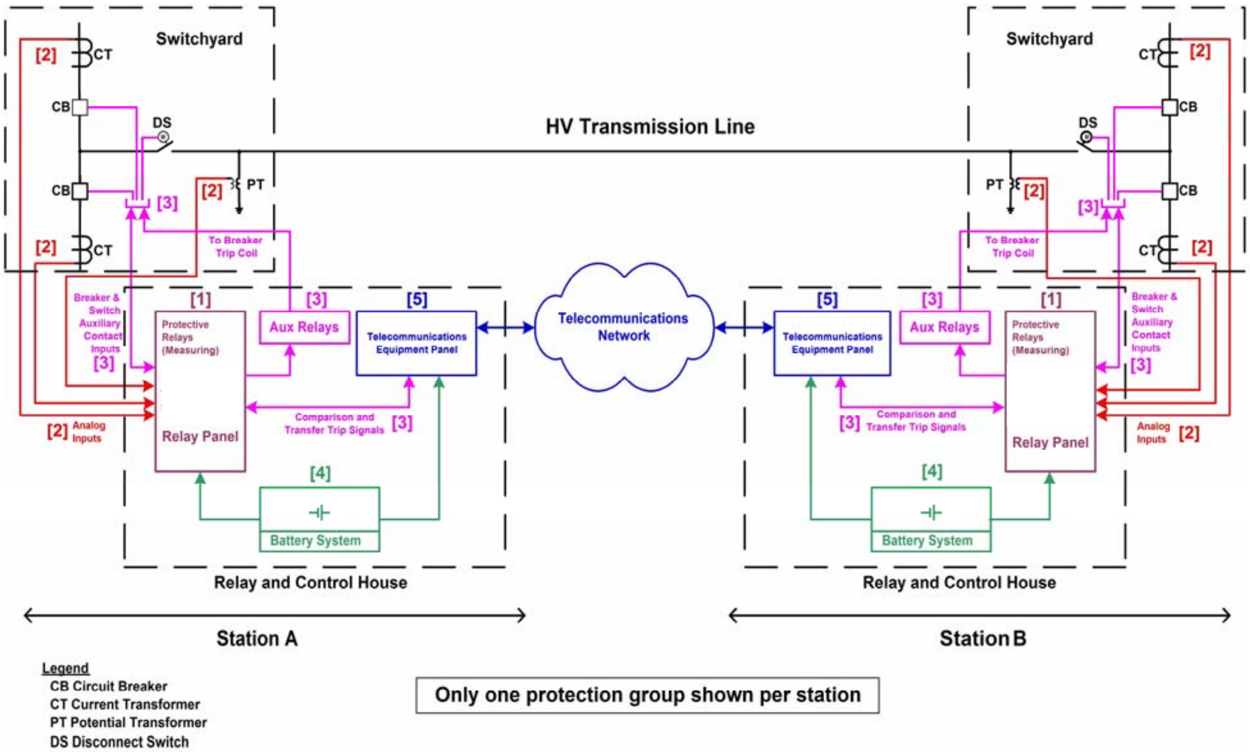
PSMT SDT References

16. "Essentials of Statistics for Business and Economics" Anderson, Sweeney, Williams, 2003
17. "Introduction to Statistics and Data Analysis" - Second Edition, Peck, Olson, Devore, 2005
18. "Statistical Analysis for Business Decisions" Peters, Summers, 1968
19. "Considerations for Maintenance and Testing of Autoreclosing Schemes," NERC System Analysis and Modeling Subcommittee and NERC System Protection and Control Subcommittee, November 2012

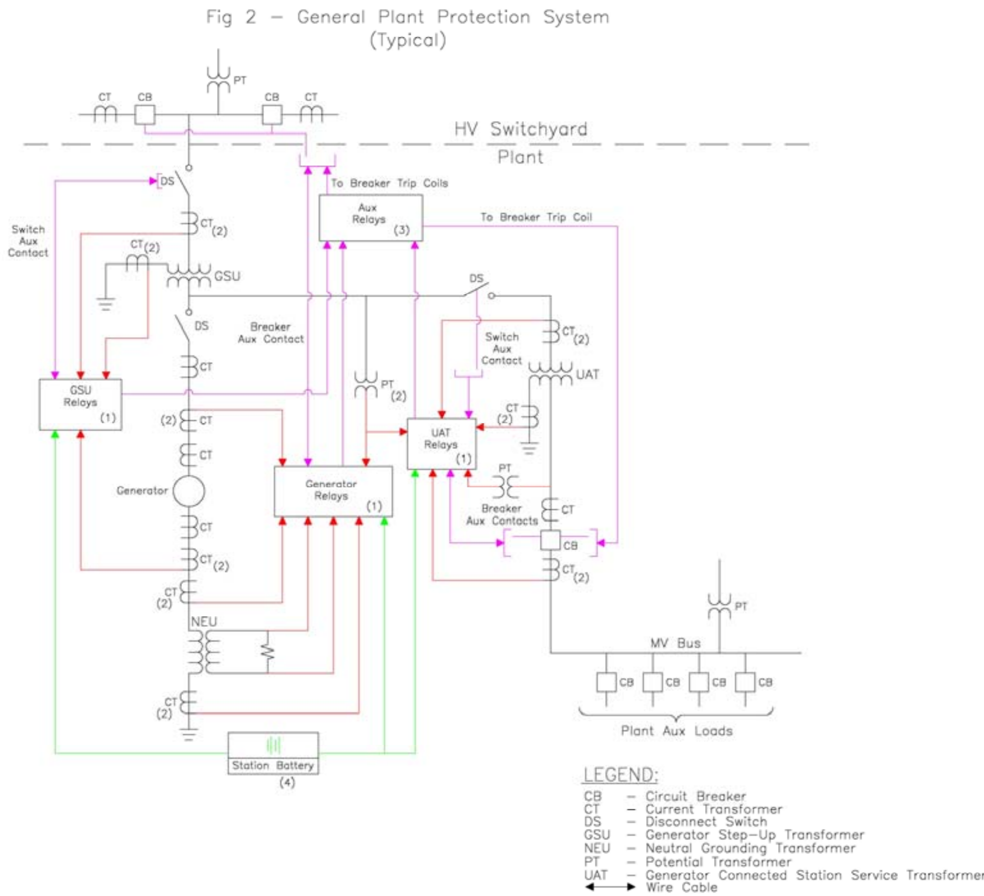
Figures

Figure 1: Typical Transmission System



For information on components, see ***Figure 1 & 2 Legend – components of Protection Systems***

Figure 2: Typical Generation System



Note: Figure 2 may show elements that are not included within PRC-005-2, and also may not be all-inclusive; see the Applicability section of the standard for specifics.

For information on components, see ***Figure 1 & 2 Legend – components of Protection Systems***

Figure 1 & 2 Legend – Components of Protection Systems

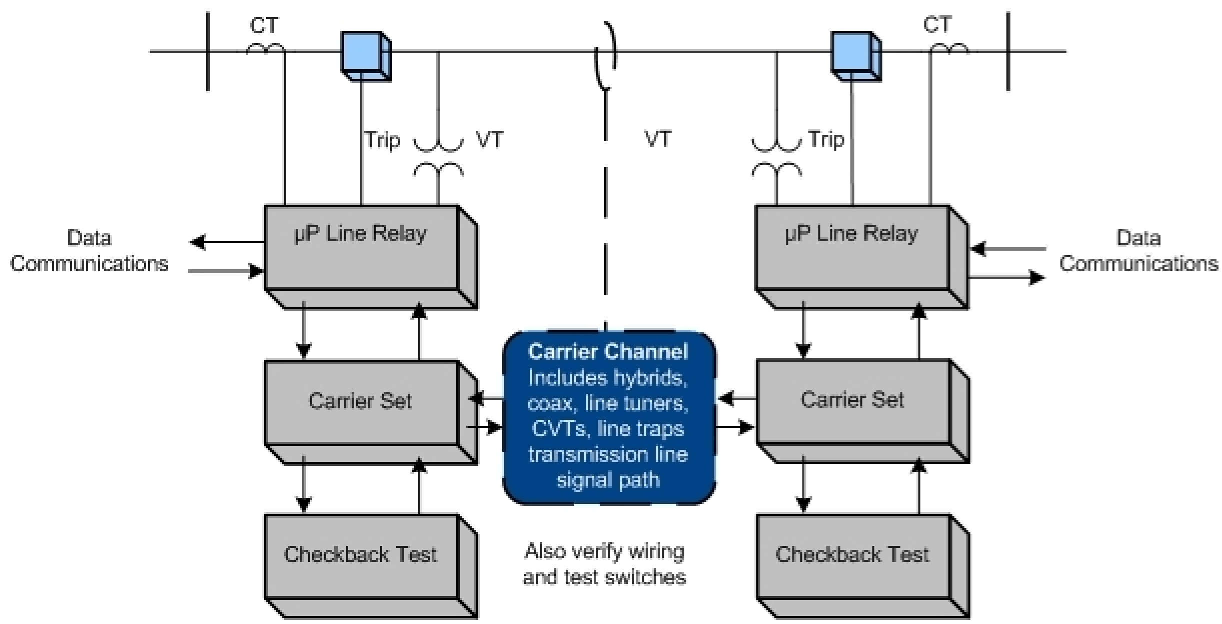
Number in Figure	Component of Protection System	Includes	Excludes
1	Protective relays which respond to electrical quantities	All protective relays that use current and/or voltage inputs from current & voltage sensors and that trip the 86, 94 or trip coil.	Devices that use non-electrical methods of operation including thermal, pressure, gas accumulation, and vibration. Any ancillary equipment not specified in the definition of Protection Systems. Control and/or monitoring equipment that is not a part of the automatic tripping action of the Protection System
2	Voltage and current sensing devices providing inputs to protective relays	The signals from the voltage & current sensing devices to the protective relay input.	Voltage & current sensing devices that are not a part of the Protection System, including sync-check systems, metering systems and data acquisition systems.
3	Control circuitry associated with protective functions	All control wiring (or other medium for conveying trip signals) associated with the tripping action of 86 devices, 94 devices or trip coils (from all parallel trip paths). This would include fiber-optic systems that carry a trip signal as well as hard-wired systems that carry trip current.	Closing circuits, SCADA circuits, other devices in control scheme not passing trip current
4	Station dc supply	Batteries and battery chargers and any control power system which has the function of supplying power to the protective relays, associated trip circuits and trip coils.	Any power supplies that are not used to power protective relays or their associated trip circuits and trip coils.
5	Communications systems necessary for correct operation of protective functions	Tele-protection equipment used to convey specific information, in the form of analog or digital signals, necessary for the correct operation of protective functions.	Any communications equipment that is not used to convey information necessary for the correct operation of protective functions.

Additional information can be found in References

Appendix A

The following illustrates the concept of overlapping verifications and tests as summarized in Section 10 of the paper. As an example, Figure A-1 shows protection for a critical transmission line by carrier blocking directional comparison pilot relaying. The goal is to verify the ability of the entire two-terminal pilot protection scheme to protect for line Faults, and to avoid over-tripping for Faults external to the transmission line zone of protection bounded by the current transformer locations.

Figure A-1



In this example (Figure A1), verification takes advantage of the self-monitoring features of microprocessor multifunction line relays at each end of the line. For each of the line relays themselves, the example assumes that the user has the following arrangements in place:

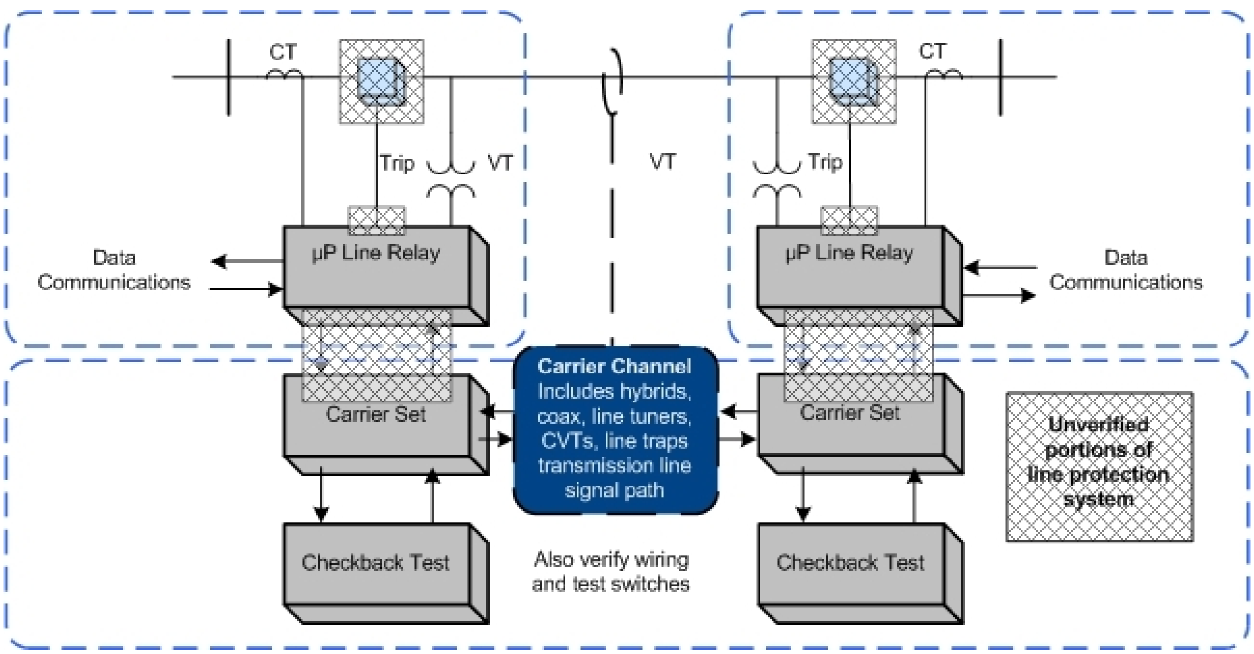
1. The relay has a data communications port that can be accessed from remote locations.
2. The relay has internal self-monitoring programs and functions that report failures of internal electronics, via communications messages or alarm contacts to SCADA.
3. The relays report loss of dc power, and the relays themselves or external monitors report the state of the dc battery supply.
4. The CT and PT inputs to the relays are used for continuous calculation of metered values of volts, amperes, plus Watts and VARs on the line. These metered values are reported by data communications. For maintenance, the user elects to compare these readings to those of other relays, meters, or DFRs. The other readings may be from redundant relaying or measurement systems or they may be derived from values in other protection zones. Comparison with other such readings to within required relaying accuracy verifies voltage & current sensing devices, wiring, and analog signal input processing of the relays. One

effective way to do this is to utilize the relay metered values directly in SCADA, where they can be compared with other references or state estimator values.

5. Breaker status indication from auxiliary contacts is verified in the same way as in (2). Status indications must be consistent with the flow or absence of current.
6. Continuity of the breaker trip circuit from dc bus through the trip coil is monitored by the relay and reported via communications.
7. Correct operation of the on-off carrier channel is also critical to security of the Protection System, so each carrier set has a connected or integrated automatic checkback test unit. The automatic checkback test runs several times a day. Newer carrier sets with integrated checkback testing check for received signal level and report abnormal channel attenuation or noise, even if the problem is not severe enough to completely disable the channel.

These monitoring activities plus the check-back test comprise automatic verification of all the Protection System elements that experience tells us are the most prone to fail. But, does this comprise a complete verification?

Figure A-2



The dotted boxes of Figure A-2 show the sections of verification defined by the monitoring and verification practices just listed. These sections are not completely overlapping, and the shaded regions show elements that are not verified:

1. The continuity of trip coils is verified, but no means is provided for validating the ability of the circuit breaker to trip if the trip coil should be energized.

2. Within each line relay, all the microprocessors that participate in the trip decision have been verified by internal monitoring. However, the trip circuit is actually energized by the contacts of a small telephone-type "ice cube" relay within the line protective relay. The microprocessor energizes the coil of this ice cube relay through its output data port and a transistor driver circuit. There is no monitoring of the output port, driver circuit, ice cube relay, or contacts of that relay. These components are critical for tripping the circuit breaker for a Fault.
3. The check-back test of the carrier channel does not verify the connections between the relaying microprocessor internal decision programs and the carrier transmitter keying circuit or the carrier receiver output state. These connections include microprocessor I/O ports, electronic driver circuits, wiring, and sometimes telephone-type auxiliary relays.
4. The correct states of breaker and disconnect switch auxiliary contacts are monitored, but this does not confirm that the state change indication is correct when the breaker or switch opens.

A practical solution for (1) and (2) is to observe actual breaker tripping, with a specified maximum time interval between trip tests. Clearing of naturally-occurring Faults are demonstrations of operation that reset the time interval clock for testing of each breaker tripped in this way. If Faults do not occur, manual tripping of the breaker through the relay trip output via data communications to the relay microprocessor meets the requirement for periodic testing.

PRC-005-X does not address breaker maintenance, and its Protection System test requirements can be met by energizing the trip circuit in a test mode (breaker disconnected) through the relay microprocessor. This can be done via a front-panel button command to the relay logic, or application of a simulated Fault with a relay test set. However, utilities have found that breakers often show problems during Protection System tests. It is recommended that Protection System verification include periodic testing of the actual tripping of connected circuit breakers.

Testing of the relay-carrier set interface in (3) requires that each relay key its transmitter, and that the other relay demonstrate reception of that blocking carrier. This can be observed from relay or DFR records during naturally occurring Faults, or by a manual test. If the checkback test sequence were incorporated in the relay logic, the carrier sets and carrier channel are then included in the overlapping segments monitored by the two relays, and the monitoring gap is completely eliminated.

Appendix B

Protection System Maintenance Standard Drafting Team

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Standards Announcement Reminder

Project 2007-17.3 Protection System Maintenance and Testing: Sudden Pressure Relays
PRC-005-X

Additional Ballot and Non-Binding Poll Now Open through September 12, 2014

Now Available

An additional ballot for **PRC-005-X – Protection System, Automatic Reclosing, and Sudden Pressure Relaying Maintenance** and non-binding poll of the associated Violation Risk Factors (VRFs) and Violation Severity Levels (VSLs) are open through **8 p.m. Eastern on Friday, September 12, 2014.**

Instructions for Balloting

Members of the ballot pools associated with this project may log in and submit their vote for the standard and non-binding poll of the associated VRFs and VSLs by clicking here.

Note: If a member cast a vote in the initial ballot, that vote will not carry over to the additional ballot. It is the responsibility of the registered voter in the ballot pool to cast a vote again in the additional ballot. To ensure a quorum is reached, if you do not want to vote affirmative or negative, please cast an abstention.

Next Steps

The ballot results will be announced and posted on the project page. The drafting team will consider all comments received during the formal comment period and, if needed, make revisions to the standard and post it for an additional ballot. If the comments do not show the need for significant revisions, the standard will proceed to a final ballot.

For more information on the **Standards Development Process**, please refer to the Standard Processes Manual.

For more information or assistance, please contact Wendy Muller,
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Standards Announcement

Project 2007-17.3 Protection System Maintenance and Testing: Sudden Pressure Relays
PRC-005-X

Formal Comment Period Now Open through September 12, 2014

Now Available

A 45-day formal comment period for **PRC-005-X – Protection System, Automatic Reclosing, and Sudden Pressure Relaying Maintenance** is open through **8 p.m. Eastern on Friday, September 12, 2014.**

If you have questions, please contact Jordan Mallory via email or by telephone at (404) 446-9733. Background information for this project can be found on the project page.

Instructions for Commenting

Please use the electronic form to submit comments on the standard. If you experience any difficulties in using the electronic form, please contact Wendy Muller. An off-line, unofficial copy of the comment form is posted on the project page.

Next Steps

An additional ballot for the standard and non-binding poll of the associated Violation Risk Factors and Violation Severity Levels will be conducted **September 3-12, 2014.**

For more information on the **Standards Development Process**, please refer to the Standard Processes Manual.

For more information or assistance, please contact Wendy Muller,
Standards Development Administrator, or at 404-446-2560.

North American Electric Reliability Corporation
3353 Peachtree Rd, NE
Suite 600, North Tower
Atlanta, GA 30326
404-446-2560 | www.nerc.com

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Standards Announcement

Project 2007-17.3 Protection System Maintenance and Testing: Sudden Pressure Relays
PRC-005-X

Formal Comment Period Now Open through September 12, 2014

Now Available

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Standards Announcement

Project 2007-17.3 Protection System Maintenance and Testing – Sudden Pressure Relays
PRC-005-X

Additional Ballot and Non-Binding Poll Results

Now Available

An additional ballot for **PRC-005-X – Protection System, Automatic Reclosing, and Sudden Pressure Relaying Maintenance** and a non-binding poll of the associated Violation Risk Factors and Violation Severity Levels concluded at **8 p.m. Eastern on Friday, September 12, 2014**.

This standard achieved a quorum and received sufficient affirmative votes for approval. Voting statistics are listed below, and the Ballot Results page provides a link to the detailed results for the ballot.

Ballot	Non-Binding Poll
Quorum /Approval	Quorum/Supportive Opinions
84.33% / 76.03%	84.81% / 74.00%

Background information for this project can be found on the project page.

Next Steps
The drafting team will consider all comments received during the formal comment period and, if needed, make revisions to the standard. If the comments show the need for significant revisions, the standard will proceed to an additional comment and ballot period. If the comments do not show the need for significant revisions, the standard will proceed to a final ballot.

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Ballot Results	
Ballot Name:	Project 2007-17.3 PSMT - Sudden Pressure Relays PRC-005-X
Ballot Period:	9/3/2014 - 9/12/2014
Ballot Type:	Additional
Total # Votes:	323
Total Ballot Pool:	383
Quorum:	84.33 % The Quorum has been reached
Weighted Segment Vote:	76.03 %
Ballot Results:	The Ballot has Closed

Summary of Ballot Results

			Affirmative		Negative				
Segment	Ballot Pool	Segment Weight	# Votes	Fraction	# Votes	Fraction	Negative Vote without a Comment	Abstain	No Vote
1 - Segment 1	105	1	55	0.733	20	0.267	0	11	19
2 - Segment 2	9	0.4	4	0.4	0	0	0	4	1
3 - Segment 3	82	1	48	0.727	18	0.273	0	8	8
4 - Segment 4	28	1	12	0.6	8	0.4	0	3	5
5 - Segment 5	88	1	45	0.703	19	0.297	0	9	15
6 - Segment 6	54	1	29	0.707	12	0.293	0	4	9
7 - Segment 7	2	0.1	0	0	1	0.1	0	0	1
8 - Segment 8	4	0.3	3	0.3	0	0	0	0	1
9 - Segment 9	2	0.2	2	0.2	0	0	0	0	0

10 - Segment 10	9	0.8	8	0.8	0	0	0	0	1
Totals	**383**	**6.8**	**206**	**5.17**	**78**	**1.63**	**0**	**39**	**60**

Individual Ballot Pool Results

Segment	Organization	Member	Ballot	NERC Notes
1	Ameren Services	Eric Scott	Affirmative	
1	American Electric Power	Paul B Johnson	Affirmative	
1	American Transmission Company, LLC	Andrew Z Pusztai	Abstain	
1	Arizona Public Service Co.	Robert Smith		
1	Associated Electric Cooperative, Inc.	John Bussman	Affirmative	
1	ATCO Electric	Glen Sutton	Abstain	
1	Austin Energy	James Armke	Negative	SUPPORTS THIRD PARTY COMMENTS - (Thomas Standifur)
1	Avista Utilities	Heather Rosentrater	Affirmative	
1	Balancing Authority of Northern California	Kevin Smith	Affirmative	
1	Baltimore Gas & Electric Company	Christopher J Scanlon	Affirmative	
1	BC Hydro and Power Authority	Patricia Robertson	Abstain	
1	Black Hills Corp	Wes Wingen		
1	Bonneville Power Administration	Donald S. Watkins	Affirmative	
1	Bryan Texas Utilities	John C Fontenot	Affirmative	
1	CenterPoint Energy Houston Electric, LLC	John Brockhan	Affirmative	
1	Central Electric Power Cooperative	Michael B Bax	Affirmative	
1	Central Iowa Power Cooperative	Kevin J Lyons	Affirmative	
1	City and County of San Francisco	Lenise Kimes	Abstain	
1	City of Tacoma, Department of Public Utilities, Light Division, dba Tacoma Power	Chang G Choi	Negative	SUPPORTS THIRD PARTY COMMENTS - Keith Morisette, Tacoma Power
1	City of Tallahassee	Daniel S Langston	Negative	COMMENT RECEIVED
1	Clark Public Utilities	Jack Stamper	Affirmative	
1	Colorado Springs Utilities	Shawna Speer	Negative	SUPPORTS THIRD PARTY COMMENTS - (Colorado Springs Utilities)
1	Consolidated Edison Co. of New York	Christopher L de Graffenried	Affirmative	
1	CPS Energy	Glenn Pressler	Affirmative	
1	Dairyland Power Coop.	Robert W. Roddy	Affirmative	
1	Dayton Power & Light Co.	Hertzel Shamash	Affirmative	
1	Dominion Virginia Power	Larry Nash	Negative	SUPPORTS THIRD PARTY COMMENTS - (Dominion)
1	Duke Energy Carolina	Doug E Hils	Affirmative	
1	Duquesne Light Co.	Hugh R Conley		
1	East Kentucky Power Coop.	Amber Anderson	Affirmative	
1	Empire District Electric Co.	Ralph F Meyer		
1	Encari	Steven E Hamburg		
1	Entergy Transmission	Oliver A Burke	Affirmative	
1	FirstEnergy Corp.	William J Smith	Affirmative	
1	Florida Keys Electric Cooperative Assoc.	Dennis Minton	Affirmative	
1	Florida Power & Light Co.	Mike O'Neil	Affirmative	
1	Gainesville Regional Utilities	Richard Bachmeier	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA)
1	Georgia Transmission Corporation	Jason Snodgrass	Negative	COMMENT RECEIVED
1	Great River Energy	Gordon Pietsch	Affirmative	

1	Hoosier Energy Rural Electric Cooperative, Inc.	Bob Solomon		
1	Hydro One Networks, Inc.	Muhammed Ali	Affirmative	
1	Hydro-Quebec TransEnergie	Martin Boisvert	Negative	SUPPORTS THIRD PARTY COMMENTS - (Hydro-Quebec TransEnergie)
1	Idaho Power Company	Molly Devine	Negative	COMMENT RECEIVED
1	International Transmission Company Holdings Corp	Michael Moltane	Affirmative	
1	JDRJC Associates	Jim D Cyrulewski	Abstain	
1	JEA	Ted E Hobson	Negative	COMMENT RECEIVED
1	Kansas City Power & Light Co.	Daniel Gibson	Affirmative	
1	Keys Energy Services	Stanley T Rzad		
1	Lakeland Electric	Larry E Watt	Negative	SUPPORTS THIRD PARTY COMMENTS - (Florida Municipal Power Agency (FMPA))
1	Lee County Electric Cooperative	John Chin	Abstain	
1	Lincoln Electric System	Doug Bantam	Affirmative	
1	Long Island Power Authority	Robert Ganley	Negative	SUPPORTS THIRD PARTY COMMENTS - (Public Service Enterprise Group)
1	Los Angeles Department of Water & Power	faranak sarbaz	Negative	COMMENT RECEIVED
1	Lower Colorado River Authority	Martyn Turner	Affirmative	
1	M & A Electric Power Cooperative	William Price	Affirmative	
1	Manitoba Hydro	Jo-Anne M Ross	Negative	COMMENT RECEIVED
1	MidAmerican Energy Co.	Terry Harbour	Affirmative	
1	Minnkota Power Coop. Inc.	Daniel L Inman	Abstain	
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey	Affirmative	
1	National Grid USA	Michael Jones	Affirmative	
1	NB Power Corporation	Alan MacNaughton	Abstain	
1	Nebraska Public Power District	Jamison Cawley	Negative	COMMENT RECEIVED
1	New York Power Authority	Bruce Metruck	Affirmative	
1	Northeast Missouri Electric Power Cooperative	Kevin White	Affirmative	
1	Northeast Utilities	William Temple	Affirmative	
1	Northern Indiana Public Service Co.	Julaine Dyke	Negative	SUPPORTS THIRD PARTY COMMENTS - (Joe O'Brien comments on behalf of Alan Neff - NIPSCO)
1	NorthWestern Energy	John Canavan		
1	Ohio Valley Electric Corp.	Scott R Cunningham	Affirmative	
1	Oklahoma Gas and Electric Co.	Terri Pyle	Affirmative	
1	Omaha Public Power District	Doug Peterchuck	Affirmative	
1	Oncor Electric Delivery	Jen Fiegel	Affirmative	
1	Otter Tail Power Company	Daryl Hanson		
1	Pacific Gas and Electric Company	Bangalore Vijayraghavan		
1	Platte River Power Authority	John C. Collins	Affirmative	
1	Portland General Electric Co.	John T Walker	Negative	COMMENT RECEIVED - PGE, Angela P Gaines - (PGE will submit comments for all PGE votes on this ballot.)
1	Potomac Electric Power Co.	David Thorne	Affirmative	
1	PPL Electric Utilities Corp.	Brenda L Truhe	Affirmative	
1	Public Service Company of New Mexico	Laurie Williams	Abstain	

1	Public Service Electric and Gas Co.	Kenneth D. Brown	Negative	SUPPORTS THIRD PARTY COMMENTS - (Support comments of Public Service Enterprise Group ("PSEG").)
1	Puget Sound Energy, Inc.	Denise M Lietz	Affirmative	
1	Rochester Gas and Electric Corp.	John C. Allen	Abstain	
1	Sacramento Municipal Utility District	Tim Kelley	Affirmative	
1	Salt River Project	Robert Kondziolka	Negative	COMMENT RECEIVED
1	SaskPower	Wayne Guttormson		
1	Seattle City Light	Pawel Krupa	Affirmative	
1	Seminole Electric Cooperative, Inc.	Glenn Spurlock	Affirmative	
1	Snohomish County PUD No. 1	Long T Duong	Affirmative	
1	South Carolina Electric & Gas Co.	Tom Hanzlik		
1	South Carolina Public Service Authority	Shawn T Abrams	Abstain	
1	Southern California Edison Company	Steven Mavis	Affirmative	
1	Southern Company Services, Inc.	Robert A. Schaffeld	Affirmative	
1	Southern Illinois Power Coop.	William Hutchison		
1	Southwest Transmission Cooperative, Inc.	John Shaver	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
1	Sunflower Electric Power Corporation	Noman Lee Williams	Affirmative	
1	Tampa Electric Co.	Beth Young		
1	Tennessee Valley Authority	Howell D Scott	Affirmative	
1	Tri-State Generation & Transmission Association, Inc.	Tracy Sliman	Affirmative	
1	Tucson Electric Power Co.	John Tolo		
1	U.S. Bureau of Reclamation	Richard T Jackson		
1	United Illuminating Co.	Jonathan Appelbaum	Affirmative	
1	Vermont Electric Power Company, Inc.	Kim Moulton		
1	Westar Energy	Allen Klassen	Affirmative	
1	Western Area Power Administration	Lloyd A Linke	Affirmative	
1	Wolverine Power Supply Coop., Inc.	Michelle Clements		
1	Xcel Energy, Inc.	Gregory L Pieper		
2	BC Hydro	Venkataramakrishnan Vinnakota	Abstain	
2	California ISO	Rich Vine		
2	Electric Reliability Council of Texas, Inc.	Cheryl Moseley	Abstain	
2	Independent Electricity System Operator	Leonard Kula	Affirmative	
2	ISO New England, Inc.	Matthew F Goldberg	Abstain	
2	MISO	Marie Knox	Abstain	
2	New York Independent System Operator	Gregory Campoli	Affirmative	
2	PJM Interconnection, L.L.C.	stephanie monzon	Affirmative	
2	Southwest Power Pool, Inc.	Charles H. Yeung	Affirmative	
3	AEP	Michael E Deloach	Affirmative	
3	Alabama Power Company	Robert S Moore	Affirmative	
3	Ameren Corp.	David J Jendras	Affirmative	
3	APS	Sarah Kist	Affirmative	
3	Associated Electric Cooperative, Inc.	Todd Bennett	Affirmative	
3	Atlantic City Electric Company	NICOLE BUCKMAN	Affirmative	
3	Avista Corp.	Scott J Kinney	Abstain	
3	BC Hydro and Power Authority	Pat G. Harrington	Abstain	
3	Bonneville Power Administration	Rebecca Berdahl	Affirmative	
3	Central Electric Power Cooperative	Adam M Weber	Affirmative	
3	City of Anaheim Public Utilities Department	Dennis M Schmidt	Abstain	
3	City of Austin dba Austin Energy	Andrew Gallo		
3	City of Clewiston	Lynne Mila	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA)
3	City of Farmington	Linda R Jacobson	Abstain	
3	City of Green Cove Springs	Mark Schultz	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA)

3	City of Redding	Bill Hughes	Affirmative	
3	City of Tallahassee	Bill R Fowler	Negative	COMMENT RECEIVED
3	Colorado Springs Utilities	Jean Mueller	Negative	SUPPORTS THIRD PARTY COMMENTS - (Kaleb Brimhall)
3	ComEd	John Bee	Affirmative	
3	Consolidated Edison Co. of New York	Peter T Yost	Affirmative	
3	Consumers Energy Company	Gerald G Farringer	Affirmative	
3	Cowlitz County PUD	Russell A Noble	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA)
3	CPS Energy	Jose Escamilla	Affirmative	
3	Delmarva Power & Light Co.	Michael R. Mayer	Affirmative	
3	Dominion Resources, Inc.	Connie B Lowe	Negative	SUPPORTS THIRD PARTY COMMENTS - (Dominion's submitted comments)
3	DTE Electric	Kent Kujala	Abstain	
3	East Kentucky Power Coop.	Patrick Woods	Affirmative	
3	Empire District Electric Co.	Kalem Long		
3	FirstEnergy Corp.	Cindy E Stewart	Affirmative	
3	Florida Keys Electric Cooperative	Tom B Anthony	Affirmative	
3	Florida Municipal Power Agency	Joe McKinney	Negative	COMMENT RECEIVED
3	Florida Power Corporation	Lee Schuster	Affirmative	
3	Georgia System Operations Corporation	Scott McGough	Negative	SUPPORTS THIRD PARTY COMMENTS - (Georgia Transmission Corp)
3	Great River Energy	Brian Glover	Affirmative	
3	Hydro One Networks, Inc.	Ayesha Sabouba	Affirmative	
3	JEA	Garry Baker	Negative	SUPPORTS THIRD PARTY COMMENTS - (JEA)
3	Kansas City Power & Light Co.	Joshua D Bach	Affirmative	
3	Kissimmee Utility Authority	Gregory D Woessner		
3	Lakeland Electric	Mace D Hunter	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA)
3	Lee County Electric Cooperative	David A Hadzima	Abstain	
3	Lincoln Electric System	Jason Fortik	Affirmative	
3	Los Angeles Department of Water & Power	Mike Anctil	Negative	COMMENT RECEIVED
3	Louisville Gas and Electric Co.	Charles A. Freibert	Affirmative	
3	Manitoba Hydro	Greg C. Parent	Negative	COMMENT RECEIVED
3	MidAmerican Energy Co.	Thomas C. Mielnik	Affirmative	
3	Modesto Irrigation District	Jack W Savage	Affirmative	
3	Muscatine Power & Water	John S Bos		
3	National Grid USA	Brian E Shanahan	Affirmative	
3	Nebraska Public Power District	Tony Eddleman	Negative	SUPPORTS THIRD PARTY COMMENTS - (Nebraska Public Power District comments.)
3	New York Power Authority	David R Rivera	Affirmative	
3	Northern Indiana Public Service Co.	Ramon J Barany	Negative	SUPPORTS THIRD PARTY COMMENTS - (Joe O'brien on behalf of Alan Neff)

3	NW Electric Power Cooperative, Inc.	David McDowell	Affirmative	
3	Ocala Utility Services	Randy Hahn	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA)
3	Oklahoma Gas and Electric Co.	Donald Hargrove	Affirmative	
3	Omaha Public Power District	Blaine R. Dinwiddie	Affirmative	
3	Orlando Utilities Commission	Ballard K Mutters	Affirmative	
3	Owensboro Municipal Utilities	Thomas T Lyons	Affirmative	
3	Pacific Gas and Electric Company	John H Hagen	Affirmative	
3	Platte River Power Authority	Terry L Baker	Affirmative	
3	PNM Resources	Michael Mertz	Affirmative	
3	Portland General Electric Co.	Thomas G Ward	Abstain	
3	Potomac Electric Power Co.	Mark Yerger	Affirmative	
3	Public Service Electric and Gas Co.	Jeffrey Mueller	Negative	SUPPORTS THIRD PARTY COMMENTS - (Public Service Enterprise Group)
3	Puget Sound Energy, Inc.	Mariah R Kennedy	Affirmative	
3	Rutherford EMC	Thomas Haire		
3	Sacramento Municipal Utility District	James Leigh-Kendall	Affirmative	
3	Salt River Project	John T. Underhill	Negative	SUPPORTS THIRD PARTY COMMENTS - (Salt River Project)
3	Santee Cooper	James M Poston	Abstain	
3	Seattle City Light	Dana Wheelock	Affirmative	
3	Seminole Electric Cooperative, Inc.	James R Frauen	Affirmative	
3	Sho-Me Power Electric Cooperative	Jeff L Neas	Affirmative	
3	Snohomish County PUD No. 1	Mark Oens	Affirmative	
3	South Carolina Electric & Gas Co.	Hubert C Young		
3	Southern California Edison Company	Lujuanna Medina	Affirmative	
3	Tacoma Power	Marc Donaldson	Negative	SUPPORTS THIRD PARTY COMMENTS - (Keith Morisette)
3	Tampa Electric Co.	Ronald L. Donahey		
3	Tennessee Valley Authority	Ian S Grant	Affirmative	
3	Tri-State Generation & Transmission Association, Inc.	Janelle Marriott	Affirmative	
3	Westar Energy	Bo Jones	Affirmative	
3	Wisconsin Electric Power Marketing	James R Keller	Affirmative	
3	Wisconsin Public Service Corp.	Gregory J Le Grave		
3	Xcel Energy, Inc.	Michael Ibold	Affirmative	
4	Alliant Energy Corp. Services, Inc.	Kenneth Goldsmith	Affirmative	
4	Blue Ridge Power Agency	Duane S Dahlquist	Negative	SUPPORTS THIRD PARTY COMMENTS - (Support the comments of FMPA)
4	City of Austin dba Austin Energy	Reza Ebrahimian		
4	City of Redding	Nicholas Zettel	Affirmative	
4	City Utilities of Springfield, Missouri	John Allen	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA)
4	Consumers Energy Company	Tracy Goble	Affirmative	
4	Cowlitz County PUD	Rick Syring	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA)
4	DTE Electric	Daniel Herring	Abstain	
4	Flathead Electric Cooperative	Russ Schneider	Affirmative	
4	Florida Municipal Power Agency	Frank Gaffney	Negative	COMMENT RECEIVED
4	Fort Pierce Utilities Authority	Cairo Vanegas	Abstain	
				SUPPORTS THIRD PARTY

4	Georgia System Operations Corporation	Guy Andrews	Negative	COMMENTS - (GTC Comments)
4	Herb Schrayshuen	Herb Schrayshuen	Affirmative	
4	Illinois Municipal Electric Agency	Bob C. Thomas	Negative	COMMENT RECEIVED
4	Indiana Municipal Power Agency	Jack Alvey	Negative	SUPPORTS THIRD PARTY COMMENTS - (Florida Municipal Power Agency)
4	Integrys Energy Group, Inc.	Christopher Plante		
4	Madison Gas and Electric Co.	Joseph DePoorter	Affirmative	
4	Modesto Irrigation District	Spencer Tacke		
4	Ohio Edison Company	Douglas Hohlbaugh	Affirmative	
4	Oklahoma Municipal Power Authority	Ashley Stringer	Abstain	
4	Public Utility District No. 1 of Snohomish County	John D Martinsen	Affirmative	
4	Sacramento Municipal Utility District	Mike Ramirez	Affirmative	
4	Seattle City Light	Hao Li	Affirmative	
4	Seminole Electric Cooperative, Inc.	Steven R Wallace	Affirmative	
4	South Mississippi Electric Power Association	Steve McElhaney		
4	Tacoma Public Utilities	Keith Morisette	Negative	COMMENT RECEIVED
4	Utility Services, Inc.	Brian Evans-Mongeon	Affirmative	
4	Wisconsin Energy Corp.	Anthony Jankowski		
5	AES Corporation	Leo Bernier	Affirmative	
5	Amerenue	Sam Dwyer	Affirmative	
5	American Electric Power	Thomas Foltz	Affirmative	
5	Arizona Public Service Co.	Scott Takinen	Affirmative	
5	Associated Electric Cooperative, Inc.	Matthew Pacobit	Affirmative	
5	BC Hydro and Power Authority	Clement Ma	Abstain	
5	Boise-Kuna Irrigation District/dba Lucky peak power plant project	Mike D Kukla	Affirmative	
5	Bonneville Power Administration	Francis J. Halpin	Affirmative	
5	Brazos Electric Power Cooperative, Inc.	Shari Heino	Affirmative	
5	Calpine Corporation	Hamid Zakery	Abstain	
5	City and County of San Francisco	Daniel Mason	Abstain	
5	City of Austin dba Austin Energy	Jeanie Doty	Negative	SUPPORTS THIRD PARTY COMMENTS - (Thomas Standifur)
5	City of Redding	Paul A. Cummings	Affirmative	
5	City of Tallahassee	Karen Webb	Negative	COMMENT RECEIVED
5	City Water, Light & Power of Springfield	Steve Rose		
5	Cleco Power	Stephanie Huffman	Affirmative	
5	Cogentrix Energy Power Management, LLC	Mike D Hirst		
5	Colorado Springs Utilities	Kaleb Brimhall	Negative	SUPPORTS THIRD PARTY COMMENTS - (Colorado Springs Utilities)
5	Con Edison Company of New York	Brian O'Boyle	Affirmative	
5	Consumers Energy Company	David C Greyerbiehl	Affirmative	
5	Cowlitz County PUD	Bob Essex	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA)
5	Dairyland Power Coop.	Tommy Drea		
5	Dominion Resources, Inc.	Mike Garton	Negative	SUPPORTS THIRD PARTY COMMENTS - (Dominion)
5	DTE Electric	Mark Stefaniak	Affirmative	
5	Duke Energy	Dale Q Goodwine	Affirmative	
5	Dynegy Inc.	Dan Roethemeyer	Affirmative	
5	E.ON Climate & Renewables North America, LLC	Dana Showalter		

5	East Kentucky Power Coop.	Stephen Ricker	Affirmative	
5	EDP Renewables North America LLC	Heather Bowden		
5	El Paso Electric Company	Gustavo Estrada		
5	Empire District Electric Co.	mike l kidwell		
5	Entergy Services, Inc.	Tracey Stubbs	Affirmative	
5	Exelon Nuclear	Mark F Draper	Affirmative	
5	First Wind	John Robertson	Affirmative	
5	FirstEnergy Solutions	Kenneth Dresner	Affirmative	
5	Florida Municipal Power Agency	David Schumann	Negative	COMMENT RECEIVED
5	Great River Energy	Preston L Walsh	Affirmative	
5	Hydro-Québec Production	Roger Dufresne	Abstain	
5	Ingleside Cogeneration LP	Michelle R DAntuono	Negative	COMMENT RECEIVED
5	JEA	John J Babik	Negative	COMMENT RECEIVED
5	Kansas City Power & Light Co.	Brett Holland	Affirmative	
5	Kissimmee Utility Authority	Mike Blough	Affirmative	
5	Lakeland Electric	James M Howard	Negative	SUPPORTS THIRD PARTY COMMENTS - (Florida Municipal Power Agency)
5	Liberty Electric Power LLC	Daniel Duff	Negative	COMMENT RECEIVED
5	Lincoln Electric System	Dennis Florom	Affirmative	
5	Los Angeles Department of Water & Power	Kenneth Silver	Negative	SUPPORTS THIRD PARTY COMMENTS - (LDWP)
5	Lower Colorado River Authority	Dixie Wells	Affirmative	
5	Luminant Generation Company LLC	Rick Terrill	Affirmative	
5	Manitoba Hydro	Chris Mazur	Negative	COMMENT RECEIVED
5	Massachusetts Municipal Wholesale Electric Company	David Gordon	Negative	SUPPORTS THIRD PARTY COMMENTS - (Florida Municipal Power Agency (FMPA))
5	Muscatine Power & Water	Mike Avesing	Affirmative	
5	Nebraska Public Power District	Don Schmit	Negative	SUPPORTS THIRD PARTY COMMENTS - (Nebraska Public Power District (NPPD))
5	New York Power Authority	Wayne Sipperly	Affirmative	
5	NextEra Energy	Allen D Schriver	Affirmative	
5	North Carolina Electric Membership Corp.	Jeffrey S Brame	Affirmative	
5	Northern Indiana Public Service Co.	Michael D Melvin	Negative	SUPPORTS THIRD PARTY COMMENTS - (See Joe O'Brien comments on behalf of Alan Neff)
5	Oglethorpe Power Corporation	Bernard Johnson		
5	Oklahoma Gas and Electric Co.	Henry L Staples	Affirmative	
5	Omaha Public Power District	Mahmood Z. Safi	Affirmative	
5	Orlando Utilities Commission	Richard K Kinas		
5	Pacific Gas and Electric Company	Alex Chua	Abstain	
5	Platte River Power Authority	Christopher R Wood	Affirmative	
5	Portland General Electric Co.	Matt E. Jastram	Negative	SUPPORTS THIRD PARTY COMMENTS - (PGE)
5	PPL Generation LLC	Annette M Bannon	Affirmative	
				SUPPORTS THIRD PARTY

5	PSEG Fossil LLC	Tim Kucey	Negative	COMMENTS - (PSEG (John Seelke))
5	Public Utility District No. 1 of Lewis County	Steven Grega		
5	Public Utility District No. 2 of Grant County, Washington	Michiko Sell	Abstain	
5	Puget Sound Energy, Inc.	Lynda Kupfer	Affirmative	
5	Sacramento Municipal Utility District	Susan Gill-Zobitz	Affirmative	
5	Salt River Project	William Alkema	Negative	SUPPORTS THIRD PARTY COMMENTS - (Salt River Project)
5	Santee Cooper	Lewis P Pierce	Abstain	
5	Seattle City Light	Michael J. Haynes		
5	Snohomish County PUD No. 1	Sam Nietfeld	Affirmative	
5	South Carolina Electric & Gas Co.	Edward Magic	Abstain	
5	South Feather Power Project	Kathryn Zancanella	Affirmative	
5	Southern California Edison Company	Denise Yaffe	Affirmative	
5	Southern Company Generation	William D Shultz	Affirmative	
5	Tacoma Power	Chris Mattson	Negative	SUPPORTS THIRD PARTY COMMENTS - (Keith Morrisette)
5	Tampa Electric Co.	RJames Rocha	Abstain	
5	Tenaska, Inc.	Scott M. Helyer		
5	Tennessee Valley Authority	David Thompson	Affirmative	
5	Tri-State Generation & Transmission Association, Inc.	Mark Stein	Affirmative	
5	U.S. Army Corps of Engineers	Melissa Kurtz		
5	USDI Bureau of Reclamation	Erika Doot		
5	Westar Energy	Bryan Taggart	Affirmative	
5	Wisconsin Electric Power Co.	Linda Horn	Affirmative	
5	Wisconsin Public Service Corp.	Scott E Johnson		
5	Xcel Energy, Inc.	Mark A Castagneri	Affirmative	
6	AEP Marketing	Edward P. Cox	Abstain	
6	Ameren Missouri	Robert Quinlivan	Affirmative	
6	APS	Randy A. Young	Affirmative	
6	Associated Electric Cooperative, Inc.	Brian Ackermann	Affirmative	
6	Bonneville Power Administration	Brenda S. Anderson	Affirmative	
6	City of Austin dba Austin Energy	Lisa Martin	Negative	SUPPORTS THIRD PARTY COMMENTS - (Thomas Standifur)
6	City of Redding	Marvin Briggs	Affirmative	
6	Cleco Power LLC	Robert Hirchak	Affirmative	
6	Colorado Springs Utilities	Shannon Fair	Negative	SUPPORTS THIRD PARTY COMMENTS - (Colorado Springs Utilities)
6	Con Edison Company of New York	David Balban	Affirmative	
6	Constellation Energy Commodities Group	David J Carlson	Affirmative	
6	Dominion Resources, Inc.	Louis S. Slade		
6	Duke Energy	Greg Cecil		
6	FirstEnergy Solutions	Kevin Querry	Affirmative	
6	Florida Municipal Power Agency	Richard L. Montgomery	Negative	COMMENT RECEIVED
6	Florida Municipal Power Pool	Thomas Washburn		
6	Florida Power & Light Co.	Silvia P Mitchell	Affirmative	
6	Kansas City Power & Light Co.	Jessica L Klinghoffer	Affirmative	
6	Lakeland Electric	Paul Shipps	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA)
6	Lincoln Electric System	Eric Ruskamp	Affirmative	
6	Los Angeles Department of Water & Power	Brad Packer	Affirmative	
6	Lower Colorado River Authority	Michael Shaw	Negative	SUPPORTS THIRD PARTY

				COMMENTS - (FMPA)
6	Luminant Energy	Brenda Hampton		
6	Manitoba Hydro	Blair Mukanik	Negative	COMMENT RECEIVED
6	Modesto Irrigation District	James McFall	Affirmative	
6	New York Power Authority	Shivaz Chopra	Affirmative	
6	Northern California Power Agency	Steve C Hill		
6	Northern Indiana Public Service Co.	Joseph O'Brien	Negative	COMMENT RECEIVED
6	Oglethorpe Power Corporation	Donna Johnson	Negative	SUPPORTS THIRD PARTY COMMENTS - (GTC)
6	Oklahoma Gas and Electric Co.	Jerry Nottnagel	Affirmative	
6	Omaha Public Power District	Douglas Collins		
6	PacifiCorp	Sandra L Shaffer	Affirmative	
6	Platte River Power Authority	Carol Ballantine	Affirmative	
6	Portland General Electric Co.	Shawn P Davis	Negative	SUPPORTS THIRD PARTY COMMENTS - (PGE will file comments under separate cover)
6	Power Generation Services, Inc.	Stephen C Knapp	Affirmative	
6	Powerex Corp.	Gordon Dobson-Mack	Abstain	
6	PPL EnergyPlus LLC	Elizabeth Davis	Affirmative	
6	PSEG Energy Resources & Trade LLC	Peter Dolan	Negative	SUPPORTS THIRD PARTY COMMENTS - (Public Service Enterprise Group)
6	Public Utility District No. 1 of Chelan County	Hugh A. Owen	Abstain	
6	Sacramento Municipal Utility District	Diane Enderby	Affirmative	
6	Salt River Project	William Abraham	Negative	SUPPORTS THIRD PARTY COMMENTS - (Salt River Project)
6	Santee Cooper	Michael Brown	Abstain	
6	Seattle City Light	Dennis Sismaet	Affirmative	
6	Seminole Electric Cooperative, Inc.	Trudy S. Novak	Affirmative	
6	Snohomish County PUD No. 1	Kenn Backholm	Affirmative	
6	Southern California Edison Company	Joseph T Marone	Affirmative	
6	Southern Company Generation and Energy Marketing	John J. Ciza	Affirmative	
6	Tacoma Public Utilities	Michael C Hill	Negative	SUPPORTS THIRD PARTY COMMENTS - (Kieth Morisette)
6	Tampa Electric Co.	Benjamin F Smith II		
6	Tennessee Valley Authority	Marjorie S. Parsons	Affirmative	
6	Westar Energy	Grant L Wilkerson	Affirmative	
6	Western Area Power Administration - UGP Marketing	Peter H Kinney		
6	Wisconsin Public Service Corp.	David Hathaway		
6	Xcel Energy, Inc.	Peter Colussy	Affirmative	
7	Occidental Chemical	Venona Greaff	Negative	SUPPORTS THIRD PARTY COMMENTS - (Ingleside Cogeneration, LP)
7	Siemens Energy, Inc.	Frank R. McElvain		
8		David L Kiguel	Affirmative	
8		Roger C Zaklukiewicz	Affirmative	
8	Massachusetts Attorney General	Frederick R Plett	Affirmative	
8	Volkmann Consulting, Inc.	Terry Volkmann		
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson	Affirmative	

9	New York State Public Service Commission	Diane J Barney	Affirmative	
10	Florida Reliability Coordinating Council	Linda C Campbell	Affirmative	
10	Midwest Reliability Organization	Russel Mountjoy	Affirmative	
10	New York State Reliability Council	Alan Adamson	Affirmative	
10	Northeast Power Coordinating Council	Guy V. Zito	Affirmative	
10	ReliabilityFirst	Anthony E Jablonski	Affirmative	
10	SERC Reliability Corporation	Joseph W Spencer	Affirmative	
10	Southwest Power Pool RE	Bob Reynolds		
10	Texas Reliability Entity, Inc.	Karin Schweitzer	Affirmative	
10	Western Electricity Coordinating Council	Steven L. Rueckert	Affirmative	

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Washington Office: 1325 G Street, N.W. : Suite 600 : Washington, DC 20005-3801

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Non-Binding Poll Results

Project 2017-17.3 Protection System Maintenance – Sudden Pressure Relays

Non-Binding Poll Results	
Non-Binding Poll Name:	Project 2007-17.3 PSMT Sudden Pressure Relays PRC-005-X
Poll Period:	9/3/2014 - 9/12/2014
Total # Opinions:	296
Total Ballot Pool:	349
Summary Results:	84.81% of those who registered to participate provided an opinion or an abstention; 74.00% of those who provided an opinion indicated support for the VRFs and VSLs.

Individual Ballot Pool Results

Segment	Organization	Member	Opinions	NERC Notes
1	Ameren Services	Eric Scott	Abstain	
1	American Electric Power	Paul B Johnson	Abstain	
1	Arizona Public Service Co.	Robert Smith		
1	Associated Electric Cooperative, Inc.	John Bussman	Affirmative	
1	ATCO Electric	Glen Sutton	Abstain	
1	Austin Energy	James Armke	Abstain	
1	Avista Utilities	Heather Rosentrater	Affirmative	
1	Balancing Authority of Northern California	Kevin Smith	Affirmative	
1	BC Hydro and Power Authority	Patricia Robertson	Abstain	
1	Bonneville Power Administration	Donald S. Watkins	Affirmative	
1	Bryan Texas Utilities	John C Fontenot	Affirmative	
1	CenterPoint Energy Houston Electric, LLC	John Brockhan	Abstain	
1	Central Electric Power Cooperative	Michael B Bax	Affirmative	
1	Central Iowa Power Cooperative	Kevin J Lyons	Affirmative	
1	City and County of San Francisco	Lenise Kimes	Abstain	
1	City of Tacoma, Department of Public Utilities, Light Division, dba Tacoma Power	Chang G Choi	Negative	SUPPORTS THIRD PARTY COMMENTS - Keith Morisette, Tacoma Power
1	City of Tallahassee	Daniel S Langston	Negative	COMMENT RECEIVED
1	Clark Public Utilities	Jack Stamper	Affirmative	

1	Colorado Springs Utilities	Shawna Speer	Negative	SUPPORTS THIRD PARTY COMMENTS - (Colorado Springs Utilities)
1	Consolidated Edison Co. of New York	Christopher L de Graffenried	Affirmative	
1	CPS Energy	Glenn Pressler	Affirmative	
1	Dairyland Power Coop.	Robert W. Roddy	Affirmative	
1	Dayton Power & Light Co.	Hertzel Shamash	Affirmative	
1	Dominion Virginia Power	Larry Nash	Abstain	
1	Duke Energy Carolina	Doug E Hils	Affirmative	
1	East Kentucky Power Coop.	Amber Anderson	Affirmative	
1	Empire District Electric Co.	Ralph F Meyer		
1	Encari	Steven E Hamburg		
1	Entergy Transmission	Oliver A Burke	Affirmative	
1	FirstEnergy Corp.	William J Smith	Affirmative	
1	Florida Keys Electric Cooperative Assoc.	Dennis Minton	Affirmative	
1	Florida Power & Light Co.	Mike O'Neil	Affirmative	
1	Georgia Transmission Corporation	Jason Snodgrass	Negative	COMMENT RECEIVED
1	Great River Energy	Gordon Pietsch	Affirmative	
1	Hoosier Energy Rural Electric Cooperative, Inc.	Bob Solomon		
1	Hydro One Networks, Inc.	Muhammed Ali	Affirmative	
1	Hydro-Quebec TransEnergie	Martin Boisvert	Negative	SUPPORTS THIRD PARTY COMMENTS - (Hydro-Quebec TransEnergie)
1	Idaho Power Company	Molly Devine	Negative	COMMENT RECEIVED
1	International Transmission Company Holdings Corp	Michael Moltane	Abstain	
1	JDRJC Associates	Jim D Cyrulewski	Abstain	
1	JEA	Ted E Hobson	Negative	COMMENT RECEIVED
1	Kansas City Power & Light Co.	Daniel Gibson	Affirmative	
1	Keys Energy Services	Stanley T Rzad		
1	Lakeland Electric	Larry E Watt	Negative	SUPPORTS THIRD PARTY COMMENTS - (Florida Municipal Power Agency (FMPA))
1	Lee County Electric Cooperative	John Chin	Abstain	
1	Lincoln Electric System	Doug Bantam	Affirmative	
1	Long Island Power Authority	Robert Ganley	Abstain	
1	Los Angeles Department of Water & Power	faranak sarbaz	Abstain	
1	Lower Colorado River Authority	Martyn Turner	Affirmative	
1	M & A Electric Power Cooperative	William Price	Affirmative	
1	Manitoba Hydro	Jo-Anne M Ross	Negative	COMMENT RECEIVED
1	MidAmerican Energy Co.	Terry Harbour	Affirmative	

1	Minnkota Power Coop. Inc.	Daniel L Inman	Abstain	
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey	Affirmative	
1	National Grid USA	Michael Jones	Affirmative	
1	NB Power Corporation	Alan MacNaughton	Abstain	
1	Nebraska Public Power District	Jamison Cawley	Abstain	
1	New York Power Authority	Bruce Metruck	Affirmative	
1	Northeast Missouri Electric Power Cooperative	Kevin White	Affirmative	
1	Northeast Utilities	William Temple	Affirmative	
1	Northern Indiana Public Service Co.	Julaine Dyke	Negative	SUPPORTS THIRD PARTY COMMENTS - (Joe O'Brien comments on behalf of Alan Neff - NIPSCO)
1	NorthWestern Energy	John Canavan		
1	Ohio Valley Electric Corp.	Scott R Cunningham	Abstain	
1	Oklahoma Gas and Electric Co.	Terri Pyle	Affirmative	
1	Omaha Public Power District	Doug Peterchuck	Affirmative	
1	Oncor Electric Delivery	Jen Fiegel	Affirmative	
1	Otter Tail Power Company	Daryl Hanson		
1	Pacific Gas and Electric Company	Bangalore Vijayraghavan		
1	Platte River Power Authority	John C. Collins	Affirmative	
1	Portland General Electric Co.	John T Walker	Negative	COMMENT RECEIVED - PGE, Angela P Gaines - (PGE will submit comments for all PGE votes on this ballot.)
1	Potomac Electric Power Co.	David Thorne	Abstain	
1	PPL Electric Utilities Corp.	Brenda L Truhe	Affirmative	
1	Public Service Company of New Mexico	Laurie Williams	Abstain	
1	Public Service Electric and Gas Co.	Kenneth D. Brown	Abstain	
1	Puget Sound Energy, Inc.	Denise M Lietz	Affirmative	
1	Rochester Gas and Electric Corp.	John C. Allen	Abstain	
1	Sacramento Municipal Utility District	Tim Kelley	Affirmative	
1	Salt River Project	Robert Kondziolka	Negative	COMMENT RECEIVED
1	SaskPower	Wayne Guttormson		
1	Seattle City Light	Pawel Krupa	Abstain	
1	Seminole Electric Cooperative, Inc.	Glenn Spurlock	Affirmative	
1	Snohomish County PUD No. 1	Long T Duong	Affirmative	
1	South Carolina Electric & Gas Co.	Tom Hanzlik		
1	South Carolina Public Service Authority	Shawn T Abrams	Abstain	

1	Southern California Edison Company	Steven Mavis	Affirmative	
1	Southern Company Services, Inc.	Robert A. Schaffeld	Affirmative	
1	Southern Illinois Power Coop.	William Hutchison		
1	Southwest Transmission Cooperative, Inc.	John Shaver	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
1	Sunflower Electric Power Corporation	Noman Lee Williams	Affirmative	
1	Tampa Electric Co.	Beth Young		
1	Tennessee Valley Authority	Howell D Scott	Affirmative	
1	Tri-State Generation & Transmission Association, Inc.	Tracy Sliman	Affirmative	
1	Tucson Electric Power Co.	John Tolo		
1	U.S. Bureau of Reclamation	Richard T Jackson		
1	United Illuminating Co.	Jonathan Appelbaum	Affirmative	
1	Vermont Electric Power Company, Inc.	Kim Moulton		
1	Westar Energy	Allen Klassen	Affirmative	
1	Western Area Power Administration	Lloyd A Linke	Affirmative	
1	Wolverine Power Supply Coop., Inc.	Michelle Clements		
2	BC Hydro	Venkataramakrishnan Vinnakota	Abstain	
2	California ISO	Rich Vine		
2	Electric Reliability Council of Texas, Inc.	Cheryl Moseley	Abstain	
2	Independent Electricity System Operator	Leonard Kula	Affirmative	
2	ISO New England, Inc.	Matthew F Goldberg	Abstain	
2	MISO	Marie Knox	Abstain	
2	New York Independent System Operator	Gregory Campoli	Affirmative	
2	PJM Interconnection, L.L.C.	stephanie monzon	Affirmative	
2	Southwest Power Pool, Inc.	Charles H. Yeung	Abstain	
3	AEP	Michael E Deloach	Abstain	
3	Alabama Power Company	Robert S Moore	Affirmative	
3	Ameren Corp.	David J Jendras	Abstain	
3	APS	Sarah Kist	Affirmative	
3	Associated Electric Cooperative, Inc.	Todd Bennett	Affirmative	
3	Avista Corp.	Scott J Kinney	Abstain	
3	BC Hydro and Power Authority	Pat G. Harrington	Abstain	
3	Bonneville Power Administration	Rebecca Berdahl	Affirmative	
3	Central Electric Power Cooperative	Adam M Weber	Affirmative	
3	City of Anaheim Public Utilities Department	Dennis M Schmidt	Abstain	

3	City of Austin dba Austin Energy	Andrew Gallo		
3	City of Clewiston	Lynne Mila	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA)
3	City of Farmington	Linda R Jacobson	Abstain	
3	City of Green Cove Springs	Mark Schultz	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA)
3	City of Tallahassee	Bill R Fowler	Negative	COMMENT RECEIVED
3	Colorado Springs Utilities	Jean Mueller	Negative	SUPPORTS THIRD PARTY COMMENTS - (Kaleb Brimhall)
3	Consolidated Edison Co. of New York	Peter T Yost	Affirmative	
3	Consumers Energy Company	Gerald G Farringer	Affirmative	
3	Cowlitz County PUD	Russell A Noble	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA)
3	CPS Energy	Jose Escamilla	Affirmative	
3	Dominion Resources, Inc.	Connie B Lowe	Abstain	
3	DTE Electric	Kent Kujala	Abstain	
3	East Kentucky Power Coop.	Patrick Woods	Affirmative	
3	FirstEnergy Corp.	Cindy E Stewart	Affirmative	
3	Florida Keys Electric Cooperative	Tom B Anthony	Affirmative	
3	Florida Municipal Power Agency	Joe McKinney	Negative	COMMENT RECEIVED
3	Florida Power Corporation	Lee Schuster	Affirmative	
3	Georgia System Operations Corporation	Scott McGough	Negative	SUPPORTS THIRD PARTY COMMENTS - (Georgia Transmission Corp)
3	Great River Energy	Brian Glover	Affirmative	
3	Hydro One Networks, Inc.	Ayesha Sabouba	Affirmative	
3	JEA	Garry Baker	Negative	SUPPORTS THIRD PARTY COMMENTS - (JEA)
3	Kansas City Power & Light Co.	Joshua D Bach	Affirmative	
3	Kissimmee Utility Authority	Gregory D Woessner		
3	Lakeland Electric	Mace D Hunter	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA)
3	Lee County Electric Cooperative	David A Hadzima	Abstain	
3	Lincoln Electric System	Jason Fortik	Affirmative	
3	Los Angeles Department of Water & Power	Mike Anctil	Abstain	
3	Louisville Gas and Electric Co.	Charles A. Freibert		
3	Manitoba Hydro	Greg C. Parent	Negative	COMMENT RECEIVED
3	MidAmerican Energy Co.	Thomas C. Mielnik	Affirmative	
3	Modesto Irrigation District	Jack W Savage	Affirmative	
3	Muscatine Power & Water	John S Bos		
3	National Grid USA	Brian E Shanahan	Affirmative	

3	Nebraska Public Power District	Tony Eddleman	Abstain	
3	New York Power Authority	David R Rivera	Affirmative	
3	Northern Indiana Public Service Co.	Ramon J Barany	Negative	SUPPORTS THIRD PARTY COMMENTS - (Joe O'brien on behalf of Alan Neff)
3	NW Electric Power Cooperative, Inc.	David McDowell	Affirmative	
3	Ocala Utility Services	Randy Hahn	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA)
3	Oklahoma Gas and Electric Co.	Donald Hargrove	Affirmative	
3	Omaha Public Power District	Blaine R. Dinwiddie	Affirmative	
3	Orlando Utilities Commission	Ballard K Mutters	Abstain	
3	Owensboro Municipal Utilities	Thomas T Lyons	Affirmative	
3	Pacific Gas and Electric Company	John H Hagen	Affirmative	
3	Platte River Power Authority	Terry L Baker	Affirmative	
3	PNM Resources	Michael Mertz	Affirmative	
3	Portland General Electric Co.	Thomas G Ward	Abstain	
3	Public Service Electric and Gas Co.	Jeffrey Mueller	Abstain	
3	Puget Sound Energy, Inc.	Mariah R Kennedy	Affirmative	
3	Rutherford EMC	Thomas Haire		
3	Sacramento Municipal Utility District	James Leigh-Kendall	Affirmative	
3	Salt River Project	John T. Underhill	Negative	SUPPORTS THIRD PARTY COMMENTS - (Salt River Project)
3	Santee Cooper	James M Poston	Abstain	
3	Seminole Electric Cooperative, Inc.	James R Frauen	Affirmative	
3	Sho-Me Power Electric Cooperative	Jeff L Neas	Affirmative	
3	Snohomish County PUD No. 1	Mark Oens	Affirmative	
3	South Carolina Electric & Gas Co.	Hubert C Young		
3	Southern California Edison Company	Lujuanna Medina	Affirmative	
3	Tacoma Power	Marc Donaldson	Negative	SUPPORTS THIRD PARTY COMMENTS - (Keith Morisette)
3	Tampa Electric Co.	Ronald L. Donahey		
3	Tennessee Valley Authority	Ian S Grant	Abstain	
3	Tri-State Generation & Transmission Association, Inc.	Janelle Marriott	Affirmative	
3	Westar Energy	Bo Jones	Affirmative	
3	Xcel Energy, Inc.	Michael Ibold	Abstain	
4	Alliant Energy Corp. Services, Inc.	Kenneth Goldsmith	Affirmative	
4	Blue Ridge Power Agency	Duane S Dahlquist	Negative	SUPPORTS THIRD PARTY COMMENTS -

				(Support comments of FMPA)
4	City of Austin dba Austin Energy	Reza Ebrahimian		
4	City Utilities of Springfield, Missouri	John Allen	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA)
4	Consumers Energy Company	Tracy Goble	Affirmative	
4	Cowlitz County PUD	Rick Syring	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA)
4	DTE Electric	Daniel Herring	Abstain	
4	Flathead Electric Cooperative	Russ Schneider	Affirmative	
4	Florida Municipal Power Agency	Frank Gaffney	Negative	COMMENT RECEIVED
4	Georgia System Operations Corporation	Guy Andrews	Negative	SUPPORTS THIRD PARTY COMMENTS - (GTC comments)
4	Herb Schrayshuen	Herb Schrayshuen	Affirmative	
4	Illinois Municipal Electric Agency	Bob C. Thomas	Abstain	
4	Indiana Municipal Power Agency	Jack Alvey	Negative	SUPPORTS THIRD PARTY COMMENTS - (Florida Municipal Power Agency)
4	Integrys Energy Group, Inc.	Christopher Plante		
4	Madison Gas and Electric Co.	Joseph DePoorter	Abstain	
4	Ohio Edison Company	Douglas Hohlbaugh	Affirmative	
4	Public Utility District No. 1 of Snohomish County	John D Martinsen	Affirmative	
4	Sacramento Municipal Utility District	Mike Ramirez	Affirmative	
4	Seminole Electric Cooperative, Inc.	Steven R Wallace	Affirmative	
4	South Mississippi Electric Power Association	Steve McElhaney		
4	Tacoma Public Utilities	Keith Morisette	Negative	COMMENT RECEIVED
4	Utility Services, Inc.	Brian Evans-Mongeon	Abstain	
4	Wisconsin Energy Corp.	Anthony Jankowski		
5	AES Corporation	Leo Bernier	Affirmative	
5	Amerenue	Sam Dwyer	Abstain	
5	American Electric Power	Thomas Foltz	Abstain	
5	Arizona Public Service Co.	Scott Takinen	Affirmative	
5	Associated Electric Cooperative, Inc.	Matthew Pacobit	Affirmative	
5	BC Hydro and Power Authority	Clement Ma	Abstain	
5	Boise-Kuna Irrigation District/dba Lucky peak power plant project	Mike D Kukla	Affirmative	
5	Bonneville Power Administration	Francis J. Halpin	Affirmative	
5	Brazos Electric Power Cooperative, Inc.	Shari Heino	Affirmative	
5	Calpine Corporation	Hamid Zakery	Abstain	

5	City and County of San Francisco	Daniel Mason	Abstain	
5	City of Austin dba Austin Energy	Jeanie Doty	Negative	SUPPORTS THIRD PARTY COMMENTS - (Thomas Standifur)
5	City of Tallahassee	Karen Webb	Negative	COMMENT RECEIVED
5	City Water, Light & Power of Springfield	Steve Rose		
5	Cleco Power	Stephanie Huffman	Affirmative	
5	Cogentrix Energy Power Management, LLC	Mike D Hirst		
5	Colorado Springs Utilities	Kaleb Brimhall	Negative	SUPPORTS THIRD PARTY COMMENTS - (Colorado Springs Utilities)
5	Con Edison Company of New York	Brian O'Boyle	Affirmative	
5	Consumers Energy Company	David C Greyerbiehl	Affirmative	
5	Cowlitz County PUD	Bob Essex	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA)
5	Dairyland Power Coop.	Tommy Drea		
5	Dominion Resources, Inc.	Mike Garton	Abstain	
5	DTE Electric	Mark Stefaniak	Affirmative	
5	Duke Energy	Dale Q Goodwine	Affirmative	
5	Dynegy Inc.	Dan Roethemeyer	Affirmative	
5	E.ON Climate & Renewables North America, LLC	Dana Showalter		
5	East Kentucky Power Coop.	Stephen Ricker	Affirmative	
5	EDP Renewables North America LLC	Heather Bowden		
5	El Paso Electric Company	Gustavo Estrada		
5	Entergy Services, Inc.	Tracey Stubbs	Affirmative	
5	First Wind	John Robertson	Affirmative	
5	FirstEnergy Solutions	Kenneth Dresner	Affirmative	
5	Florida Municipal Power Agency	David Schumann	Negative	COMMENT RECEIVED
5	Great River Energy	Preston L Walsh	Affirmative	
5	Hydro-Québec Production	Roger Dufresne	Abstain	
5	Ingleside Cogeneration LP	Michelle R DAntuono	Negative	COMMENT RECEIVED
5	JEA	John J Babik	Negative	COMMENT RECEIVED
5	Kansas City Power & Light Co.	Brett Holland	Affirmative	
5	Kissimmee Utility Authority	Mike Blough	Affirmative	
5	Liberty Electric Power LLC	Daniel Duff	Negative	COMMENT RECEIVED
5	Lincoln Electric System	Dennis Florom	Affirmative	
5	Los Angeles Department of Water & Power	Kenneth Silver	Abstain	
5	Lower Colorado River Authority	Dixie Wells	Affirmative	
5	Luminant Generation Company LLC	Rick Terrill	Affirmative	
5	Manitoba Hydro	Chris Mazur	Negative	COMMENT RECEIVED

5	Massachusetts Municipal Wholesale Electric Company	David Gordon	Abstain	
5	Muscatine Power & Water	Mike Avesing	Affirmative	
5	Nebraska Public Power District	Don Schmit	Abstain	
5	New York Power Authority	Wayne Sipperly	Affirmative	
5	NextEra Energy	Allen D Schriver	Affirmative	
5	North Carolina Electric Membership Corp.	Jeffrey S Brame	Affirmative	
5	Northern Indiana Public Service Co.	Michael D Melvin	Negative	SUPPORTS THIRD PARTY COMMENTS - (See Joe O'Brien comments on behalf of Alan Neff)
5	Oglethorpe Power Corporation	Bernard Johnson		
5	Oklahoma Gas and Electric Co.	Henry L Staples	Affirmative	
5	Omaha Public Power District	Mahmood Z. Safi	Affirmative	
5	Orlando Utilities Commission	Richard K Kinas		
5	Pacific Gas and Electric Company	Alex Chua	Abstain	
5	Platte River Power Authority	Christopher R Wood	Affirmative	
5	Portland General Electric Co.	Matt E. Jastram	Negative	SUPPORTS THIRD PARTY COMMENTS - (PGE)
5	PPL Generation LLC	Annette M Bannon	Affirmative	
5	PSEG Fossil LLC	Tim Kucey	Abstain	
5	Public Utility District No. 1 of Lewis County	Steven Grega		
5	Public Utility District No. 2 of Grant County, Washington	Michiko Sell	Abstain	
5	Puget Sound Energy, Inc.	Lynda Kupfer	Affirmative	
5	Sacramento Municipal Utility District	Susan Gill-Zobitz	Affirmative	
5	Salt River Project	William Alkema	Negative	SUPPORTS THIRD PARTY COMMENTS - (Salt River Project)
5	Santee Cooper	Lewis P Pierce	Abstain	
5	Seattle City Light	Michael J. Haynes		
5	Snohomish County PUD No. 1	Sam Nietfeld	Affirmative	
5	South Carolina Electric & Gas Co.	Edward Magic	Abstain	
5	South Feather Power Project	Kathryn Zancanella	Affirmative	
5	Southern California Edison Company	Denise Yaffe	Affirmative	
5	Southern Company Generation	William D Shultz	Affirmative	
5	Tacoma Power	Chris Mattson	Negative	SUPPORTS THIRD PARTY COMMENTS - (Keith Morisette)
5	Tampa Electric Co.	RJames Rocha	Abstain	
5	Tenaska, Inc.	Scott M. Helyer		
5	Tennessee Valley Authority	David Thompson	Affirmative	
5	Tri-State Generation & Transmission Association, Inc.	Mark Stein		

5	U.S. Army Corps of Engineers	Melissa Kurtz		
5	USDI Bureau of Reclamation	Erika Doot		
5	Wisconsin Public Service Corp.	Scott E Johnson		
5	Xcel Energy, Inc.	Mark A Castagneri	Affirmative	
6	AEP Marketing	Edward P. Cox	Affirmative	
6	Ameren Missouri	Robert Quinlivan	Abstain	
6	APS	Randy A. Young	Affirmative	
6	Associated Electric Cooperative, Inc.	Brian Ackermann	Affirmative	
6	Bonneville Power Administration	Brenda S. Anderson	Affirmative	
6	City of Austin dba Austin Energy	Lisa Martin	Abstain	
6	Cleco Power LLC	Robert Hirchak	Affirmative	
6	Colorado Springs Utilities	Shannon Fair	Negative	SUPPORTS THIRD PARTY COMMENTS - (Colorado Springs Utilities)
6	Con Edison Company of New York	David Balban	Affirmative	
6	Duke Energy	Greg Cecil		
6	FirstEnergy Solutions	Kevin Querry	Affirmative	
6	Florida Municipal Power Agency	Richard L. Montgomery	Negative	COMMENT RECEIVED
6	Florida Municipal Power Pool	Thomas Washburn		
6	Florida Power & Light Co.	Silvia P Mitchell	Affirmative	
6	Kansas City Power & Light Co.	Jessica L Klinghoffer	Affirmative	
6	Lakeland Electric	Paul Shipps	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA)
6	Lincoln Electric System	Eric Ruskamp	Affirmative	
6	Los Angeles Department of Water & Power	Brad Packer	Affirmative	
6	Lower Colorado River Authority	Michael Shaw	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA)
6	Luminant Energy	Brenda Hampton		
6	Manitoba Hydro	Blair Mukanik	Negative	COMMENT RECEIVED
6	Modesto Irrigation District	James McFall	Affirmative	
6	New York Power Authority	Shivaz Chopra	Affirmative	
6	Northern California Power Agency	Steve C Hill		
6	Northern Indiana Public Service Co.	Joseph O'Brien	Negative	COMMENT RECEIVED
6	Oglethorpe Power Corporation	Donna Johnson	Negative	SUPPORTS THIRD PARTY COMMENTS - (GTC)
6	Oklahoma Gas and Electric Co.	Jerry Nottnagel	Affirmative	
6	Omaha Public Power District	Douglas Collins		
6	PacifiCorp	Sandra L Shaffer	Abstain	
6	Platte River Power Authority	Carol Ballantine	Affirmative	
6	Portland General Electric Co.	Shawn P Davis	Negative	COMMENT RECEIVED - PGE, Angela P

				Gaines - (PGE will file comments under separate cover)
6	Power Generation Services, Inc.	Stephen C Knapp	Affirmative	
6	Powerex Corp.	Gordon Dobson-Mack	Abstain	
6	PPL EnergyPlus LLC	Elizabeth Davis	Affirmative	
6	PSEG Energy Resources & Trade LLC	Peter Dolan	Abstain	
6	Sacramento Municipal Utility District	Diane Enderby	Affirmative	
6	Salt River Project	William Abraham	Negative	SUPPORTS THIRD PARTY COMMENTS - (Salt River Project)
6	Santee Cooper	Michael Brown	Abstain	
6	Seattle City Light	Dennis Sismaet	Affirmative	
6	Seminole Electric Cooperative, Inc.	Trudy S. Novak	Affirmative	
6	Snohomish County PUD No. 1	Kenn Backholm	Affirmative	
6	Southern California Edison Company	Joseph T Marone	Affirmative	
6	Southern Company Generation and Energy Marketing	John J. Ciza	Affirmative	
6	Tacoma Public Utilities	Michael C Hill	Negative	SUPPORTS THIRD PARTY COMMENTS - (Kieth Morisette)
6	Tampa Electric Co.	Benjamin F Smith II		
6	Tennessee Valley Authority	Marjorie S. Parsons	Abstain	
6	Western Area Power Administration - UGP Marketing	Peter H Kinney		
7	Exxon Mobil	Jay Barnett		
7	Occidental Chemical	Venona Greaff	Negative	SUPPORTS THIRD PARTY COMMENTS - (Ingleside Cogeneration, LP)
8		David L Kiguel	Affirmative	
8		Roger C Zaklukiewicz	Affirmative	
8	Massachusetts Attorney General	Frederick R Plett	Affirmative	
8	Volkmann Consulting, Inc.	Terry Volkmann		
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson	Affirmative	
10	Florida Reliability Coordinating Council	Linda C Campbell	Affirmative	
10	Midwest Reliability Organization	Russel Mountjoy	Affirmative	
10	New York State Reliability Council	Alan Adamson	Affirmative	
10	Northeast Power Coordinating Council	Guy V. Zito	Affirmative	
10	ReliabilityFirst	Anthony E Jablonski	Affirmative	
10	SERC Reliability Corporation	Joseph W Spencer	Affirmative	
10	Southwest Power Pool RE	Bob Reynolds		

10	Texas Reliability Entity, Inc.	Karin Schweitzer	Affirmative	
10	Western Electricity Coordinating Council	Steven L. Rueckert	Abstain	

Individual or group. (47 Responses)
Name (33 Responses)
Organization (33 Responses)
Group Name (14 Responses)
Lead Contact (14 Responses)
Question 1 (38 Responses)
Question 1 Comments (44 Responses)
Question 2 (34 Responses)
Question 2 Comments (44 Responses)
Question 3 (34 Responses)
Question 3 Comments (44 Responses)
Question 4 (34 Responses)
Question 4 Comments (44 Responses)
Question 5 (0 Responses)
Question 5 Comments (44 Responses)
Question 6 (0 Responses)
Question 6 Comments (44 Responses)

Group
Northeast Power Coordinating Council
Guy Zito
Yes
The deleted R6 should have been shown in the PRC-005-X posted redline.
No
The wording in the note added to the title box of Table 5 is confusing. It refers to Table 1-5, yet in the title box for Table 1-5 it states that Sudden Pressure Relaying is excluded.
Yes
This is assuming that the data retention section referred to in the question and the standard's 1.2 Evidence Retention are one in the same.
Yes
Regarding the sync-check relays mentioned in 2.4.1 Frequently Asked Questions:, because their operation is reliant upon voltage inputs, sync-check relay maintenance must be addressed in the tables, specifically maintenance done with voltages applied. Table 4-2(b) addresses control circuit paths, but verifying a control circuit path could be done by manually blocking contacts closed.
The title box for Table 1-5 refers to "...Automatic Reclosing (see Table 4)..." There is no Table 4. It should be reworded to read "Tables 4-1 through 4-2" as it reads in the title box for Table 2. The many tables and cross references between the tables in the standard make the standard difficult to use. Reorganizing the tables, possibly having one table per component type with component attributes listed should be considered.
Group
Arizona Public Service Company
Janet Smith
Yes
Yes
Yes
Yes

Group
PacifiCorp
Sandra Shaffer
Yes
Yes
Yes
Yes
Group
MRO NSRF
Joe DePoorter
Yes
The NSRF in the last posting had pointed out some issues related to the R6 requirement. With removal of the requirement in this posting those issue have been resolved. Thank you.
No
It is not clear in Table 5 if verification of the pressure or flow sensing mechanism is operable includes a test that the fault pressure relay when activated actually operates the auxiliary relay, elctromechanical lokout device or circuit breaker or other interrupting device to which it is conntected? Is it intended that this test is a part of the control circuity test of Table 5? It is recommended that a clarification be made for this issue either in Table 5 or the reference document.
No
Requirement R5 related to unresolved maintenance issues only applies when such an event occurs and that may not be associated with a particular periodic maintenance activity. It would seem more appropriate to retain records on the instances of unresolved maintenance issues that occuured since the last audit.
No
With the modifications to R3, it is implied that a newly idenfified automatic reclosing component would have the maximum maintenance interval as a deadline from when it is newly identified for its initial maintenance under the standard. This seems to be what the rationale for R3 indicates. It is suggested that be more clearly stated.
: The NSRF does not agree with the proposed wording in the Evidence Retention section, which states “In cases where the interval of the maintenance activity is shorter than the audit cycle, documentation of, all performances of that maintenance activity for the Protection System, Automatic Reclosing, or Sudden Pressure Relaying Component since the previous scheduled audit date shall be retained”. The Maximum Maintenance Interval prescribed in all Tables is the enforceable component of when each entity must complete their Maintenance Activities. Any entity may elect to perform any Maintenance Activity at anytime for any reason. The NSRF recommends that the most current documentation of the associated Maintenance Activity be maintained. The NSRF believes that maintaining ALL maintenance documentation, regardless of what the Standard states is outside the scope of the Standard and does not add to increased reliability but rather an increased risk of not maintaining ALL past maintenance documentation. If the SDT wants ALL maintenance records since the last audit, then state that and prescribed table of “intervals” will not be necessary.
Group

Colorado Springs Utilities
Kaleb Brimhall
Yes
Yes
Yes
Yes
None
Sudden pressure relays, which do trip some transformers, are not important in preventing “instability, cascading, or separation.” CSU believes that the inclusion of sudden pressure relays in the NERC Standards will not improve the reliability of the BES, and are outside the FPA Section 215 jurisdiction. The following are some additional notes on this topic. We also support FMPA's proposed language. • Many transformers are not protected using sudden pressure relays. In fact, due to the sensitivity of sudden pressure relays to vibration, some areas of the country purposefully do not use sudden pressure relays for transformer protection. • Many transformers that are protected using sudden pressure relays use a guarded trip scheme. For example, in order for the sudden pressure relay to trip the transformer there must also be another condition present such as an over current or differential trip. • There is not a consistent application of sudden pressure relays in the industry, many transformers do not utilize these relays for protection, and no requirements exist to have sudden pressure relays. CSU believes that including them in a standard will discourage their use and/or encourage those that currently use them to remove them from their protection scheme. Sudden pressure relays when applied correctly can be an asset in transformer protection, but are not important in preventing “instability, cascading, or separation.”
Individual
Mark Wilson
Independent Electricity System Operator
Yes
Yes
Yes
Yes
Individual
Thomas Foltz
American Electric Power
Yes
Yes
Yes
Yes

Table 5 – The interval for fault pressure operability is 6 calendar years, though some relays will require equipment outages to safely perform this work. AEP suggests aligining this maintenance interval with that of the associated equipment (transformers, reactors, etc.), which would typically be between 10 and 12 years within the industry. Taking this equipment out of service to perform fault pressure related maintenance would be a detriment to reliability.
Table 5 – The interval for fault pressure operability is 6 calendar years, though some relays will require equipment outages to safely perform this work. AEP suggests aligining this maintenance interval with that of the associated equipment (transformers, reactors, etc.), which would typically be between 10 and 12 years within the industry. Taking this equipment out of service to perform fault pressure related maintenance would be a detriment to reliability.
Individual
phan.si_truc@hydro.qc.ca
Hydro-Quebec TransEnergie
Yes
Yes
Yes
Yes
Hydro-Quebec TransEnergie comments from first draft has not been considered.
Individual
Andrew Pusztai
American Transmission Comany, LLC
Yes
No Comment.
No
ATC recommends that the fault pressure relay be placed on a 12 calendar year maintenance interval. The best method to test the fault pressure relay is as a system with the seal-in relay and the control circuit. The auxiliary relay and control circuit are on a 12 year cycle. The Supplementary Reference and FAQ document states that the 6 year interval was based on similar Protection System components, but there are not other Protection System components that are similar to fault pressure relaying. Smaller populations of fault pressure relays would make it more difficult to utilize performance-based invervals except for the largest utilities.
Yes
No comment.
Yes
No comment.
No comment.
No comment.
Individual
Dan Bamber
ATCO Electric
No
Transmissions owners should be informed of the generator data for determining BES generating sites.
Yes
Yes

Yes
No comments
Pressure Relief Device (PRD) works on absolute pressure threshold. Currently these is no methodology to verify PRD sensing mechanism operation simulating required pressure. Can the drafting team an answer in the FAQ to guide us. Should PRD's not belong to the sudden pressure relay category?
Individual
John Falsey
Invenergy LLC
Individual
Michelle D'Antuono
Ingleside Cogeneration LP
No
Ingleside Cogeneration LP ("ICLP") agrees that a requirement specific to Balancing Authorities (or Reserve Sharing Groups) does not need to appear in the standard, but there must be an alternative binding means to provide the same information. Otherwise it is not clear to us how we would know the size of the largest generating unit in the BA/RSG footprint – or if it has changed. For example, if the RSG member with the largest generating unit suddenly decided to leave the Reserve Sharing Group, the applicability criteria would change without notice. Similarly, it seems unlikely that the BA/RSG would provide sufficient advance notification that the largest unit in their footprint is being decommissioned; reasoning that this is somewhat confidential information. As it stands now, the possibility exists that every affected Generator Owner and Transmission Owner would be found in violation of PRC-005-X based upon an action outside of their control or knowledge. This is inconsistent with reasonable principles of reliability compliance as we understand them.
Yes
ICLP fully agrees with the changes made to Table 5. By taking these actions, the project team has established consistency with the other control circuitry activities and intervals – which we have found reduces ambiguity in our compliance process and internal controls.
Yes
ICLP believes that the project team has fully captured FERC's intent in their recently issued NOPR to approve PRC-005-3. We agree that there is no reliability purpose served in maintaining Protection System test records that may be a decade or older just to confirm compliance with long interval activities. There should be plenty of other evidence that a relay owner has sufficiently strong internal controls necessary for an adequate BES Protection System Maintenance Program.
No
Similar to our response to Question 1, ICLP needs assurance that a sufficient grace period is provided to the recloser owner when the applicability criteria changes in the BA/RSG footprint. The integration of previously non-applicable reclosers into our PSMP could take years until an opportunity to perform relay and control circuitry testing presents itself. We were satisfied with the three years previously allowed under R3 and R4 – and those time frames should be captured somewhere in a binding manner. As it stands now, Draft 2 of PRC-005-X seems to stipulate that the change in applicability would take effect immediately, an unrealistic proposition in our view.
Individual
Joe O'Brien on behalf of Alan Neff
NIPSCO
No

All Sudden Pressure Relays do not affect the reliable operation of the BES. Some Sudden Pressure Relays are installed for equipment monitoring and other functions. We are suggesting that the language include mandatory maintenance and testing for only those relays that are used to support the reliable operation of the BES. It should be noted that this testing requires a vacuum setup and/or removal of the relay from the transformer. The relay will add many hours to the time required to test each transformer protection package.
Individual
David Thorne
Pepco Holdings Inc
Yes
Yes
Yes
Yes
no
no
Individual
Oliver Burke
Entergy Services, Inc.
Individual
Robert W. Kenyon
NERC
Yes
Yes
Yes
Yes
Comments on PRC-005-X September 11, 2014 I should mention that the following comments are presented from the point of view of enforcing the standard, not from the point of view of a Protection Engineer. Moreover, the comments are guided by the philosophy that we enforce the explicit Requirements put forth within the Standard. To be an enforceable matter, an explicit statement clearly stating the explicit obligations should be provided within the Standard. Requirement 1 Requirement 1 does not present a complete and unambiguous statement as to the obligations imposed on the Registered Entity. There is no clear statement as to what has to be documented in the Registered Entity PSMP. There are two parts provided, but these are in fact the only specific elements mentioned. The intent of these Parts is unclear. As written, they simply require the entity to identify whether the entity uses BPM, TBM, or a combination in each COMPONENT TYPE. COMPONENT TYPE simply alludes to whether relays, batteries, etc. are being addressed. Thus if an entity uses only TBM for relays, it can so state. No data on individual components is required. There will be 9 component types when PRC-005-X is in force. To comply, all an entity will need to do is to list the nine types and next to each identify which approach (TBM, BPM, and Combination) is used within that component TYPE. The value of this information is hard to identify. Part 1.2 obligates the entity to identify attributes used to extend maintenance intervals, if such use is made. Complying with that, as written, merely obligates the entity to list the 9

component types and any attributes which any components with each COMPONENT TYPE may be using to extend the interval. Again, no information on any individual Component is required. Again, the purpose of obligating the entity to create such a list is unclear. It must be emphasized that as written, these Parts focus on the COMPONENT TYPE - NOT the Components. A careful reading of these parts reveals that they only obligate to list some information relating to the COMPONENT TYPE level - the value of which is hard to discern. Unfortunately, these two Parts (1.1 1nd 1.2) are the only specific obligations imposed on the entity by the Standard. To be of any use, a PSMP would require vastly more information, particularly considering the amount of very detailed maintenance tasks required by PRC-005-X. Yet by including only Parts 1.1 and 1.2, it is implied that only the lists provided above are required in the PSMP. Entities could justifiably believe they were in compliance by simply creating the two lists alluded to above. Note that PRC-005-1 EXPLICTLY obligates the entity to include in its program identification of maintenance intervals and procedures. The situation will be basically the same under PRC-005-X. Although NERC has now imposed maximum intervals and minimum activities, the entity still must determine its own program. The NERC interval and activities requirements are limits within which the entity still must develop its own program, as it did under PRC-005-1. Why has this Standard dropped the obviously essential need to identify the factors such as interval and activities in the PSMP? If that were not the intent, why are some specific obligations (Part 1.1 and Part 1.2) identified and others not? Suggest that Requirement 1 be re-written, dropping the existing Part 1.1 and 1.2, because they appear to provide no useful information, being limited by their language to the COMPONENT TYPE level. Parts should be added identifying specific requirements in the PSMP document, such as intervals, maintenance activities, and other essential specifics for a useful and effective PSMP. All specific activities, policies, etc. needed to comprise an effective PSMP should be identified in a Requirement 1 Part. Requirement 2 There are numerous issues with Requirement 2. In general, some elements are presented in a confusing manner, at least one is erroneous, and the Requirement does not address situations which following Requirement 2 will eventually lead to. Requirement 2 identifies procedures that the entity must follow, first to establish PBM Segments, and then to annually maintain the justification for using each individual Segment. These rules are not stated in Requirement 2 itself. Instead, the entity is referred to Attachment A of PRC-005-X. Some steps in Attachment A are difficult to understand. Requirement 2, Attachment A, Establishing Justification, Step 2. Step 2 obligates the entity to: “Maintain the Components in each Segment according to the time-based maximum allowable intervals established in Tables 1-1 through 1-5, Table 3, Tables 4-1 through 4-2, and Table 5 until results of maintenance activities for the Segment are available for a minimum of 30 individual Components of the Segment.” But note that “Tables 1-1 through 1-5, ….” referenced above establish not only the “maximum allowable interval” but also “minimum maintenance activities”. Yet Step 2 above provides a clear requirement to follow the table “Intervals”, while making no mention of the table-prescribed “minimum activities”. Recommend that the Step be re-written establishing clearly whether Step 2 requires the use of both the “maximum intervals” (as specified) and the “minimum activities” (left uncertain). Requirement 2, Attachment A, Establishing Justification, Step 4 To establish a PBM Segment, the entity is directed to identify components for the Segment, maintain so many of these, and use the results to determine a revised maintenance interval. The determination is provided at Step 4 of the process in Attachment A alluding to “establishing” justification for PBM. But although the entity is directed to determine the upcoming year interval, no guidance on how to do this is provided. An earlier Reference Document strongly implied that the interval cannot be extended unless the previous Countable Events Rate does not exceed 4%. However, no such restrictions appears in the Requirement. Are entities forbidden to extend maintenance intervals if during the “establishment” phase they encounter a CE rate exceeding 4%? If so, this should be explicitly stated. Note that an entity most certainly could follow Attachment A when establishing a Segment, have a CE rate exceeding 4%, and still reasonably conclude that an extended interval was warranted. As an example, a CE rate exceeding 4% may have been realized but the entity has concluded that the rate was an anomaly, based upon a subsequently uncovered manufacturing issue with a very small batch of devices. The point is, what is the intent of Step 4 in the “establishing” section – is the entity precluded from selecting a longer interval if it experiences a CE rate exceeding 4%? One reference document strongly suggests so, but there is no such proscription in the Standard. In short, Step 4 should be clarified as to whether a 4% or less CE rate must be achieved before PBM intervals can be established. Requirement 2, Attachment A, Establishing Justification, Step 5 The intent of Step 5 in the “establishment” process seems to be to direct the entity to identify a maximum interval for the upcoming year, based on the previous year's performance, such that in the upcoming year, the segment will experience a CE rate not exceeding 4%. The actual wording is: Determine the maximum allowable maintenance interval for each Segment such that the Segment experiences Countable Events on no more than 4% of the Components within the Segment, for the greater of either the last 30 Components maintained or all Components maintained in the previous year. This statement is very confusing and should be revised. One aspect contributing to the confusion is that the term "maximum allowable maintenance interval" apparently alludes, analogously, to the "Maximum Intervals" identified in the various Tables (Table 1-1, 1-2, etc.). But since the interval term is not defined and not in the glossary, and the term is not capitalized, the normal interpretation is that the entity must develop a generic "maximum" that will prevent a CE Rate exceeding 4% - which is not mathematically possible. The requirement should more clearly state that using the previous year's data, try to identify the longest interval which will most likely not result in a CE Rate exceeding 4%, in the upcoming year. Inconsistency Regarding Mandatory Countable Event Performance As an aside, the steps in Attachment A identify a PBM limit not exceeding 4%, while the corrective action requirement indicates that the CE rate must be LESS THAN 4%. While the difference is small, the difference (Less than 4% vs. not to exceed 4%) should be rationalized. Requirement 2, Attachment A, Maintaining Justification, Step 1 In the "maintaining justification" section, Step 1 obligates the entity to update the Component List. Presumably, this would include adding Components. Note that rather stringent requirements covering establishment of a PBM Segment are provided. Segments cannot be created without following the rules of Attachment A. But no guidance is provided addressing adding Components to an existing Segment. Suggest a clear statement in the Standard that during the updates, any component having the properties of the Segment can be added to the Segment. Presumably, the update will include dropping retired components form the Segment. No guidance is provided in the Standard addressing dropping Components at the will of the entity. Is this permitted? Moreover, there is no guidance as to what the entity must do when the Segment population drops below the mandatory 60 Components. A clear statement is made in the Standard that a Segment must be at least 60 Components. Maintaining a Segment of less than 60 components via PBM is clearly identified in the Standard as a violation. What are the rules when attrition or, perhaps, dropping Components voluntarily brings the Segment population below 60 Components? Presumably, the use of PBM on that Segment must be discontinued. But what rules apply? Perhaps, the entity must revert to TBM. But having using PBM, many if not all of the Components will not have been maintained under the TBM rules. Therefore, if the Segment is simply dropped back into the TBM rules, the entity could well be forced into maintaining every single Component in the Segment in one year, which, could exceed the maintenance capabilities of the entity. There is no guidance covering these instances, which over time, will occur with every PBM Segment established. Recommend guidance be provided. Presumably, if new components are added to the entity system, perhaps they can simply be added to the Segment population. However, no guidance is provided as to whether this is mandatory. Note that Step 1 of the "Maintain" process does explicitly obligate the Entity to "update" the Segment. Guidance should be provided as to whether the obligation stated in the standard to "update" the Segment includes mandatory additions of new components on the system with the attributes of the Segment. Again, recommend guidance be provided. Requirement 2, Attachment A, Maintaining Justification, Step 2 Step 2 in the "maintain justification" rules obligates the entity to: Perform maintenance on the greater of 5% of the Components (addressed in the performance based PSMP) in each Segment or 3 individual Components within the Segment in each year. The intent of this Step is to establish a "floor" on maintenance performed. It should read: Perform maintenance on AT LEAST the greater of 5% of the Components (addressed in the performance based PSMP) in each Segment or 3 individual Components within the Segment in each year. The Standard Provides no Means to Prevent the Entity from "Gaming the System" to Drastically Reducing Maintenance Activity Note that following the procedures provided in Attachment A, a given entity will probably have no devices to maintain in the year following the establishment of a Segment. This is because, presumably, the entity was following TBM intervals, and the purpose of PBM is to extend those intervals. As an example, an entity would have maintained all its unmonitored relays at a 6 year interval under TBM. After establishing a PBM Segment for these for the next year, the entity will be establishing a new interval which could well be 8 or 9 years. Since the entity had been maintaining these relays under the TBM six year interval, but a newly established Segment of 8 years is now in place under PBM, that will leave the entity with nothing to test in the following year, since everything was already maintained with the last 6 years. Under Step 2 above, the entity will still have to test at least 5% of the population. There is nothing preventing the entity from re-testing that 5% of the population which was tested most recently. This will probably result in a very low CE rate, probably zero, which will obligate the entity to again test under the 5% rule of Step 2 in the following year. Again, there is nothing preventing the entity to again re-test the same devices it's been now testing for two years in a row, and it appears this could continue for many years. Thus PBM as established in the Standard apparently can be manipulated or "gamed" in manner that all but stops maintenance but leaves the entity 100% compliant with the Standard. Provisions should be added which close this gap. Requirement 2, Attachment A, Maintaining Justification, Step 3 Under the "establish" section of Attachment A, the Standard explicitly obligates the entity analyze the results of its maintenance activity for the year, and to "develop maintenance intervals". Thus the entity is reasonably obligated to determine the interval for the next year based on an analysis of the past year's performance. However, in the corresponding section on "Maintaining" justification for PBM intervals, Step 3, the obligation on the entity to analyze "to develop intervals" is missing. Instead, the entity is merely obligated to: "For the prior year, analyze the maintenance program activities and results for each Segment to determine the overall performance of the Segment." Nowhere in the Section describing the "maintenance of PBM" is the entity obligated to use the results of the past year's maintenance to determine the interval for the next year. This obligation appears in the section of Attachment A as to "establishing" the Segment. But the obligation is not in the Section of Attachment A as to "Maintaining" the justification for PBM. In fact, there is no explicit obligation anywhere in Attachment A requiring the entity to take into account the performance of the previous year and thereby determine the Interval for the next year while maintaining the justification for Segment intervals in an upcoming year (unless the CE exceeds 4%). An earlier Reference document indicated that that is required. It appears the by oversight, the obligation on the entity to consider new Intervals each year based on the previous year's performance was dropped. Verbiage should be added making determination of the Interval for the following year be made by an analysis of the past year's performance. Presently, the only similar obligation on the entity while "maintaining" justification for ongoing use is the phrase "determine the overall performance of the Segment" in Step 3 of the "maintaining" section, which falls well short of an explicit obligation to thereby establish or a least consider now intervals. Recommend revising Step 3 such that a clear requirement be established that the entity evaluate its existing interval and determine whether adjustment is necessary, based on the prior year's performance. Requirement 2, Attachment A, Maintaining Justification, Step 4 Step 4 of the Attachment A section covering "maintaining" technical justification presents the same problems mentioned above regarding Step 5 of the rules for "establishing" justification for PBM Segments. The Table of Compliance Elements identifies failure by the entity to Reduce the CE Rate to 4% over three years as a violation, but the Standard does not establish this as a Requirement. The final line of Attachment A provides: "If the Components in a Segment maintained through a performance-based PSMP experience 4% or more Countable Events, develop, document, and implement an action plan to reduce the Countable Events to less than 4% of the Segment population within 3 years." The above obligates the entity to do an action plan to reduce the CE rate to 4%. That's all. As written, this would permit the entity to go on forever with a CE rate exceeding 4% every year without penalty, as long as they had the plan, it was credible, documented, and executed. Yet the PRC-005-X "Table of Compliance Elements" identifies FAILURE to reduce the CE Rate as a Violation. Suggest the Standard be revised such that REDUCING the CE Rate to 4% or less is established as a Requirement. The Requirements in the Standard do not impose this obligation presently. The only such obligation in the Standard as written is to do the Action Plan, with no mention of success or failure. The standard is establishing a new obligation in the "Table of Compliance Elements" that is not supported by the Requirements in the Standard. The requirement, as written, does not obligate the entity to be successful; only to try. Suggest that bringing the CE Rate down to 4 % or less be established in the Standard as a clear Requirement. Drop Attachment A and place its Requirements in Requirement 2, with each Step established as a Part Requirement 2 is presented in an awkward manner. Requirement 2 provides nothing and simply refers the entity to Attachment A of the standard. There's no apparent reason for this. Attachment A provides requirements for establishing PBM Segments, maintaining them, and a third requirement for action plans. The requirements for establishing and maintaining the technical justifications are provided in numbered "Steps", with both processes using the same number sequence, so there are two Steps 1 and two Steps 2, etc. The Action plan material is not numbered. This makes referring to the various steps, etc. awkward. This problem could be fixed by dropping Attachment A, and numbering all its requirements as "Parts" of Requirement 2, providing clear identification of each element.

Recommend this be done. Requirement 3 Requirement 3 revolves around embedded tables that prescribe minimum maintenance activities and maximum intervals for Protection System components. The tables contain several sets of maintenance activities and minimum activities, for several different possible Component attribute configurations. However, the specific sets of intervals and activities are not numbered or otherwise identified. Thus, to refer to a specific set of intervals and activities, one is forced to use awkward language such as "the third row down in Table 1-1". Recommend that these sets of intervals and activities each be provided a number or other identification system permitting efficient identification of each set. Requirement 3 and 4 Both Requirements 3 and 4 are very similar in that both obligate maintenance being performed. One uses TBM or extended TBM, while the other uses PBM. But the overall intent in both is the same: Do the maintenance. Note that under both Requirements, the Standard establishes MINIMUM maintenance activities which must be performed. However, these are MINIMUM Requirements, and the Entity may indeed and probably will add activities to its own program. So while the entity program will include the minimum activities specified in the Standard, the entity program will also include activities identified and desired by the entity. This is true for both Requirement 3 and Requirement 4, in both TBM and PBM. However, a close reading of these two Requirements reveals that they impose significantly different obligations. Requirement 3 requires: "Each Transmission Owner, Generator Owner, and Distribution Provider that utilizes time-based maintenance program(s) shall maintain its Protection System, Automatic Reclosing, and Sudden Pressure Relaying Components that are included within the time-based maintenance program in accordance with the minimum maintenance activities and maximum maintenance intervals prescribed within Tables 1-1 through …" However. Requirement 4 requires: "Each Transmission Owner, Generator Owner, and Distribution Provider that utilizes performance-based maintenance program(s) in accordance with Requirement R2 shall implement and follow its PSMP for its Protection System, Automatic Reclosing, and Sudden Pressure Relaying Components that are included within the performance-based program(s)." Note that R3 requires the entity to simply meet the minimum requirements in the Tables, while R4 requires the entity to "implement and follow its PSMP for its Protection System, Automatic Reclosing, and Sudden Pressure Relaying Components that are included within the performance-based program(s). In other words, R3 does not obligate the entity to do the maintenance activities it selected on its own, but R4 does, since in contrast it requires the entity to "implement and follow its PSMP", which presumably would have to include the maintenance activities added to the PSMP by the entity. Recommend this disconnect be reviewed and rationalized. There is no apparent reason for there being different obligations under R3 and R4. Having different requirements could motivate entities to not add desirable additional testing to avoid jeopardy. It could also lead to confusion as to just what the Requirements are. Requirement 5 This requires: "Each Transmission Owner, Generator Owner, and Distribution Provider shall demonstrate efforts to correct identified Unresolved Maintenance Issues." However, the Evidence Retention Section of the Standard makes no mention of the data required to evaluate entity compliance with this requirement and establishes no retention period. Obviously, data from prior years will be required to evaluate compliance. Evidence Retention Section The "Evidence Retention" section does not establish data retention periods for entity retention of information documenting its establishment of PBM Segments or the justification for the continuing use of PBM (Requirement 2). Maintaining the justification for the continuing use of all PBM Segments is an annual Requirement and is at the heart of the entire PBM process. Its importance is reflected in the VSL Level associated with failure to develop these justifications – SEVERE. Yet the "Evidence Retention" section of the Standard imposes no retention period for the rather extensive documentation required to ensure such justifications were performed. Recommend that the "Evidence Retention" section be revised to require the entity to retain all documents and evidence to support the establishment and maintenance of the justifications for PBM Segments. It is recognized that M2 states that the entity must have such evidence FOR ITS CURRENT PROGRAM. Recognizing that developing the technical justification for every Segment is an ANNUAL REQUIREMENT, and that TOs will probably be audited every 6 years, if the data retention is limited to the Current Program, then compliance with R2 can never be audited with respect to 5 out of every 6 PBM Segment programs developed. Evaluation of compliance for the five years will not be possible. Again, recommend that the "Evidence Retention" section be revised to require keeping all technical justification documentation prepared since the last audit. Data Base Issue As written, the standard does not require the entity to maintain data on its usually vast Protection System in any orderly manner. Note that large entities will have populations in the thousands of Components. It is recognized that there would probably be issues gaining universal acceptance of any one format, but

convenient access to data will be essential for Auditing purposes as well as management of the Protection System Function by the Entity. As an example, the audit team will need to evaluate compliance with maintenance intervals. But without knowing whether a component is maintained under PBM or TBM, whether monitoring has been applied, what the present and past variable PBM intervals have been (if applicable), and the specific table under which a Component is being maintained, evaluation of compliance with the complex rules will be impossible. This is but one example. Recommend that NERC consider developing a standard format for Protection System Components. Consideration should be given to developing an associated application which can periodically import maintenance records and conduct an evaluation of compliance. Such an application could also assist the entity in managing its maintenance.
Individual
John Seelke
Public Service Enterprise Group
PSEG supports the comments submitted by Florida Municipal Power Agency (FMPA) In addition, PSEG provides the following additional comments: PSEG, like many TOs and GOs, has Sudden Pressure Relays (SPRs) as a third level of transformer protection – primary and backup transformer differential relays would isolate the transformer in case of a fault. For some TOs or GOs, the SPR is a backup to its primary transformer differential relay. In this this case, SPRs should be tested under PRC-005-X. However, in the first case, no maintenance interval should be required by a NERC standard since primary and backup differential relays are both subject to PRC-005-X testing. (As practical matter, SPRs that are a third level of protection would be tested as good utility practice during the normal transformer maintenance, which has on its own maintenance interval that's unrelated to SPR maintenance.)
Group
Dominion
Mike Garton
No
If the BA is not required to provide this information, applicable entities under this standard will not have the information necessary to determine whether they have applicable Facilitie(s) under 4.2.6.1.
Yes
Yes
Yes
No.
Yes; Dominion commends the SDT for its articulate summary of changes.
Individual
Jo-Anne Ross
Manitoba Hydro
Yes
No
Errors in the text of Table 5 remain. It fails to differentiate the maintenance interval between monitored and un-monitored elements. The suggested change is: Change Component Attributes from "Control circuitry associated with Sudden Pressure Relaying" to "Unmonitored control circuitry

associated with Sudden Pressure Relaying from the fault pressure relay to the interrupting device trip coil(s).”
Yes
Yes
1. The revisions proposed effectively include all sudden pressure relays regardless of their reliability impact on the Bulk Electric System (BES). The Standards Development Team (SDT) is requested to develop criteria to reasonably identify and include only those sudden pressure relays that are essential and possibly disruptive in the BES, thus reducing the burden of the regulation and making it acceptable to the industry. 2. The Special Protection and Control Subcommittee (SPCS) provided good guidance but did not identify the maximum maintenance interval. Comments provided in the round of voting ending June 3, 2014 indicate that intervals of up to 12 years are routinely acceptable. This is also the maximum interval at Manitoba Hydro. This varies significantly from the informal survey by the SPCS with their conclusion of 6 years. The regulated maximum maintenance interval should consider typical industry maximums plus an allowance for minor variations to provide equipment availability. The SPCS should provide the maximum with consideration to the application, capability, loading, and reliability impact on the BES.
Individual
Karin Schweitzer
Texas Reliability Entity
Yes
Yes
Yes
Yes
No comments.
Texas Reliability Entity, Inc. (Texas RE) supports this version of PRC-005-X and will vote affirmative in the ballot. We do, however, have suggested revisions for the definition of Countable Event. 1. Texas RE suggests that the first sentence of the definition, as written, appears to include each “condition” (i.e. issue) not each “’Component’ with an issue” discovered during a maintenance cycles as e a Countable Event. Is it the intent of the SDT that if a relay had multiple issues discovered during a maintenance cycle that it would be considered as one countable event since countable events are defined at the Component level? It appears that the first sentence of the “Countable Event” definition allows multiple Countable Events for each maintenance of each Component. That could mean the maintenance of a single relay with multiple issues could push a Registered Entity’s Countable Events to well over 4%. This potential appears to exist because the first sentence’s second defined item says that a Countable Event is “any condition discovered during the maintenance activities in Tables 1-1 through 1-5, Table 3, Tables 4-1 through 4-2, and Table 5, which requires corrective action”. Texas RE suggests a revision to the first sentence of the definition for Countable Event, as follows (bracketed area represents new/changed text): A failure of a Component requiring repair or replacement, any [Component] condition discovered during the maintenance activities in Tables 1-1 through 1-5, Table 3, Tables 4-1 through 4-2, and Table 5, [to have one or more conditions which requires corrective action or a Protection System Misoperation attributed to hardware failure or calibration failure.] 2. Texas RE also suggests that the second sentence of the definition, as written, has unclear language that could result in different interpretations as to which Misoperations do not qualify as Countable Events. Texas RE suggests a revision to the second sentence of the definition for Countable Event, as follows (bracketed area represents new/changed text): Misoperations due to [any of the following are not included in Countable Events: product design errors, software errors, relay settings different from specified

settings, or errors with either configuration or application in Components of Protection Systems, Automatic Reclosing, or Sudden Pressure Relaying.]
Individual
Jonathan Meyer
Idaho Power Company
No
An Entity within a BA area could find itself out of compliance if they are not notified of the largest generating unit. Requiring an Entity to query the BA regularly seems unnecessary as the BA should always be aware of the largest unit and more easily in a position to notify its BA members.
Yes
Yes
No
Is it the intent of the DT to have a newly identified component only maintained prior to the maximum interval allowed for that component type in the Tables? This would be our interpretation if no additional clarifying language is added. A timing Requirement or additional language is needed if this is not the case.
No
No
Individual
David Jendras
Ameren
Yes
Ameren agrees with the SERC PCS response to this question and includes it by reference.
Yes
(1) We believe that stating the lockout relay and monitored control circuitry maintenance activities in Table 5 repeats what's in Table 1-5, and thus superfluous. (2) The note below the title of Table 5 implies to us that if such Components differ from those in Table 1-5, they are outside Applicability in both PRC-005-2 and PRC-005-3. Is that correct?
Yes
Yes
Ameren agrees with the SERC PCS response to this question and includes it by reference.
(1) Ameren agrees with the SERC PCS response to this question and includes it by reference. (2) We understand the use of 'pressure or flow sensing' within the first Table 5 Maintenance Activity is within the context of the PRC-005-X Fault pressure relay definition and therefore does not include other types of pressure or oil flow devices found on transformers. Correct?
Individual
Jamison Cawley
Nebraska Public Power District
Yes
No
We feel the current draft of Table 5 is too broad in the use of the term,"Any Fault Pressure Relay". The SCPS report conclusion (Page 31) indicates, "Where the device is installed to respond to rapid pressure rise in facilities described in the applicability section of Reliability Standard PRC-005, and configured to take action to initiate fault clearing to support reliable operation of the Bulk-Power System, it should be included as a device to be maintained and tested". Since many SPR devices are installed simply to protect equipment from excessive loss of life (or simply indication) rather than to

provide fault detection or clearing for the BES, the mandatory inclusion of Any Fault Pressure Relay to the PSMP via Table 5 falls outside the intended scope of the SPCS report. Additional validation of this interpretation is gained from the previous sentence in the SPCS document: “Where this device is applied to respond to abnormal equipment conditions, it takes action to protect the equipment from excessive loss of life or to indicate unavailability of service, rather than for the purpose of initiating fault clearing or mitigating an abnormal system condition to support reliable operation of the Bulk-Power System”. We feel if the device is not providing support for reliable operation of the Bulk Power System it should be excluded from the PSMP.
Yes
Yes
Individual
Than Aung
Los Angeles Department of Water and Power
Yes
No
LADWP does not support the addition sudden pressure relay to the PRC-005 standard due to the non-electrical fault nature of these devices.
Yes
Yes
Individual
Keith Morisette
Tacoma Power
Yes
While Tacoma Power does not support making PRC-005-X applicable to Balancing Authorities, removal of Requirement R6 does create additional burden for Transmission Owners, Generator Owners, and Distribution Providers to keep current on which Automatic Reclosing is applicable to PRC-005-X.
No
Tacoma Power does not support modification of the standard to include Sudden Pressure Relaying and therefore opposes inclusion of Table 5 in its entirety.
No
While Tacoma Power does support the proposed modifications to the data retention section for Requirements R2, R3, R4, and R5, the first paragraph of the section undermines the proposed modifications by granting the CEA authority to “ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit,” which could include retaining evidence from the previous audit period.
No
In the PRC-005-X Implementation Plan, Tacoma Power was not able to identify where cases were addressed in which Automatic Reclosing became applicable to the standard based upon changes to the largest relevant BES generating unit. Whether it is included in the Implementation Plan or the body of the standard, it is vital that Transmission Owners, Generator Owners, and Distribution Providers be afforded a reasonable timeframe to conduct and document the first testing under Tables 4-1 and 4-2(a), not only during initial implementation, but also in response to changes in

applicability. These entities may not receive much advance notice of changes in applicability, and it is unreasonable to require that they be compliant before the change in applicability takes place when the change in applicability is being triggered by another entity that is not required to provide notice to all impacted entities. (The wording in Footnote 2 reinforces this concern.)
No.
Yes. Recognizing that even the technical report acknowledges that “[t]here is no operating experience in which misoperation of a pressure switch in response to a system disturbance has contributed to a cascading event,” it is a concern that an enforceable regulatory requirement to maintain sudden pressure relays will be established based upon a theoretical risk of inadvertent operation during a disturbance that might contribute to a cascading event. Consequently, unless evidence can be produced of actual inadvertent operation of sudden pressure relays protecting BES elements during a disturbance that, under slightly different system conditions, could have led to a cascading event (i.e., a “near miss”), modification of PRC-005 to address sudden pressure relaying should not be necessary at this time. Furthermore, as mentioned on page 4 of the Summary of Comments, “FERC stated that any component that detects any quantity needed to take an action, or that initiates any control action (initial tripping, reclosing, lockout, etc.) affecting the reliability of the Bulk-Power System should be included as a component of a Protection System. Accordingly, to address FERC’s concern, pursuant to section 215 (d)(5) of the FPA, FERC proposed to direct NERC to develop a modification to the Reliability Standard to include any component or device that is designed to detect defective lines or apparatuses or other power system conditions of an abnormal or dangerous nature and to initiate appropriate control circuit actions.” This argument in favor of including sudden pressure relaying could easily be extrapolated in the future to include other equipment protective functions such as (but not limited to) IEEE 26, 49, and 71 functions. There is concern that the SPCS report’s recommendation not to include these functions could be disregarded in the future after the industry has acclimated to regulated testing of sudden pressure relaying.
Individual
Israel Beasley
Georgia Transmission Corporation
Yes
Yes
Yes
No
We could only agree if the issue were addressed in the implementation plan. The removal of a direct statement regarding newly identified Automatic Reclosing Components from both the standard and the implementation plan (see Rationale for R3 and Rationale for R4) leaves the initial maintenance required date ambiguous. We suggest the following addition to the implementation plan: “Newly identified Automatic Reclosing Components shall be treated as being commissioned on the date of discovered applicability for the purposes PRC-005-X. The first maintenance records for newly identified Automatic Reclosing Components shall be dated no later than the maximum maintenance interval after the identification date. The maximum maintenance intervals for each newly identified Component are defined in Tables 1-1 through 1-5, Table 2, and Table 4. No activities or records are required prior to the date of identification.”
The change listed in response to question 4 probably should also be added to the FAQ.
Individual
Bill Fowler
City of Tallahassee

The City of Tallahassee (TAL) believes Sudden Pressure Relaying should not be added to PRC-005-X because they are not necessary for the “reliable operation” of the bulk power system as defined in statute. What is necessary for the reliable operation of the BPS are differential relays, overcurrent relays, etc., that are there to clear a major phase to ground or phase to phase fault that if left uncleared can cause instability. The purpose for a sudden pressure relay is primarily to monitor equipment health, e.g., detecting a turn-to-turn failure, not a phase to ground or phase to phase fault. If a sudden pressure relay fails to operate, there is no threat to BPS reliability since the differential relay / overcurrent relays are there if the fault develops into a major phase to ground or phase to phase fault. TAL believes that the use of sudden pressure relays are a good business practice, but we also believe that utilities should be free to adopt good business practice beyond the requirements of the standards, without the reverse incentives that being regulated, audited, etc., bring.
Individual
Gul Khan
Oncor Electric Delivery
Yes
Yes
Yes
Yes
Group
Florida Municipal Power Agency
Carol Chinn
Yes
No
See comments for Question 6
Yes
Yes
1) In Order No. 758, the Commission accepted NERC’s proposal to the NOPR to develop technical documents (SPCS report) to determine those protective relays that are necessary for the reliable operation of the Bulk-Power System and allow for differentiation between protective relays that detect faults from other devices that monitor the health of the individual equipment and are advisory in nature (e.g., oil temperature). Currently as drafted this standard, PRC 005-X, may apply to Sudden Pressure Relays installed for equipment monitoring and protection. This is due to the fact that, as currently drafted, the Applicability section for Facilities (4.2.1) is too broad due to the inclusion of the term “Fault” and how that term is defined in the NERC Glossary: “4.2.1 Protection Systems and Sudden Pressure Relaying that are installed for the purpose of detecting Faults on BES Elements (lines, buses, transformers, etc.)” NERC Glossary definition of Fault: “An event occurring on an electric system such as a short circuit, a broken wire, or an intermittent connection.” If the glossary term only referenced “short circuit”, then this would not be a problem. But the fact that broken wires and intermittent connections are part of the definition for Fault, this greatly broadens the term Fault to include potential events that would have little to no reliability impact to the BES,

such as turn to turn faults in wound electrical apparatus. Consequently, the use of the term Fault as proposed in the Applicability section of this draft standard PRC-005-X unnecessarily broadens the Applicability of the standard to include devices which do not have a BES reliability related purpose. Suggested language that can be incorporated to help meet the FERC directive and address the reliability concerns is as follows: "Sudden Pressure Relays that are installed as the primary or back-up relay for the purpose of detecting phase-to-ground or phase-to-phase short circuit on the BES." Clarifying the Applicability with this phrase focuses the standard applicability to testing of devices that are relied upon to clear short circuits of sufficient magnitude to have a reliability impact. That is, the proposed language results in testing that is focused on devices for which there is a reliability-related need to confirm the positive operation of the device. 2). Additionally, Fault is not used in 4.2.5, and as such GSU transformer applicability is even more encompassing. Again, suggest modifying 4.2.5 to say "Sudden Pressure Relaying installed for the purpose of detecting phase-phase and phase-ground short circuit on the BES and Protection Systems for generator facilities that are part of the BES, including: …" 3.) The proposed definition of Sudden Pressure Relaying is inconsistent with the SPCS report analysis of the 63 device function number in Appendix D (page 31 of SPCS report). The 63 device function number discussion, in its entirety, focuses on gas and oil PRESSURE relays. Furthermore, although not stated, the discussion and description of performance history and issues with these relays is specific to transformer tank mounted gas and oil pressure relays. The proposed definition of Sudden Pressure Relaying adds the term "oil flow" to the definition of a "Fault Pressure Relay", a term not mentioned or addressed by the SPCS report. This definitively includes Bucholz relays in the definition of Sudden Pressure Relaying and, hence, the new applicability. Although Bucholz relays typically respond to both pressure and oil flow, the pressure detection method is quite different from tank mounted pressure relays. Industry literature and operating history, including reports on fault pressure relaying that pre-date the SPCS report (and which were relied upon by the SPCS), indicate there is little risk of Bucholz relay misoperation due to external faults and no such known misoperations. By extrapolating the language of the SPCS report, the SDT has expressly included devices that were not discussed or postulated by the SPCS, and which have little to no risk of misoperation for external faults. If the only differentiator and justification for including sudden pressure relays in the PRC-005 standard/applicability is the risk of operation for external faults, then Bucholz relays should be explicitly excluded. Due to the dual operating functions of the relay, FMPA believes the only straightforward solution is to directly exclude these devices. Simply removing the phrase "oil flow" does not fully resolve the issue. FMPA requests this comment be considered on its own merits, but given extra emphasis should FMPA's suggestion regarding the purpose of the installed sudden pressure relaying not be addressed by the SDT.
Individual
Christy Koncz
Public Service Enterprise Group
These comments replace previous comments submitted on 9/11/14 by John Seelke of Public Service Enterprise Group. PSEG supports the comments submitted by Florida Municipal Power Agency (FMPA) In addition, PSEG provides the following additional comments: PSEG, like many TOs and GOs, has Sudden Pressure Relays (SPRs) as a third level of transformer protection – primary and backup transformer differential relays would isolate the transformer in case of a fault. For some TOs or GOs, the SPR is a backup to its primary transformer differential relay. In this this case, SPRs should be tested under PRC-005-X. However, in the first case, no maintenance interval should be required by a NERC standard since primary and backup differential relays are both subject to PRC-005-X testing. (As practical matter, SPRs that are a third level of protection would be tested as good utility practice during the normal transformer maintenance, which has on its own maintenance interval that's unrelated to SPR maintenance.) Furthermore, any internal transformer fault, including turn-to-turn short circuits, whether detected by the SPR or the differential relay, will generally put the transformer out of service and beyond repair. The use of the SPR MIGHT help avoid some

environmental impact, but does not add to the reliability of the BES in any way and will not save the transformer. Finally, when used in conjunction with redundant differential schemes, the application of the SPR for tripping purposes is not required as noted above. This being the case, if the standard passes “as is,” TOs and GOs that do not currently perform testing at the prescribed intervals in the standard will meet compliance requirements by either 1) Decreasing the transformer maintenance interval or by 2) Rewiring the SPR as an alarm function. For PSEG, decreasing the maintenance interval will require removing the BES transformers from service approximately twice as often as they are now. That presents a reliability concern. Removing the SPR from the tripping state to the alarm state does not present a NERC BES reliability concern, and as such we will be forced to consider this option.
Individual
Scott Langston
City of Tallahassee
Yes
The City of Tallahassee (TAL) believes Sudden Pressure Relaying should not be added to PRC-005-X because they are not necessary for the “reliable operation” of the bulk power system as defined in statute. What is necessary for the reliable operation of the BPS are differential relays, overcurrent relays, etc., that are there to clear a major phase to ground or phase to phase fault that if left uncleared can cause instability. The purpose for a sudden pressure relay is primarily to monitor equipment health, e.g., detecting a turn-to-turn failure, not a phase to ground or phase to phase fault. If a sudden pressure relay fails to operate, there is no threat to BPS reliability since the differential relay / overcurrent relays are there if the fault develops into a major phase to ground or phase to phase fault. TAL believes that the use of sudden pressure relays are a good business practice, but we also believe that utilities should be free to adopt good business practice beyond the requirements of the standards, without the reverse incentives that being regulated, audited, etc., bring.
Group
DTE Electric Co.
Kathleen Black
Yes
Yes
Yes
Yes
No
No
Group
JEA
Tom McElhinney
Yes

Yes
The standard needs to be limited to items that take action to initiate fault clearing and should not include items that are simply meant to protect equipment.
Individual
Daniel Duff
Liberty Electric Power LLC
Yes
No
Disagree with the handling of sudden pressure relays. The added requirement for electical testing of the lockout relay should be deleted. Typically the physical seperation of the pathway by the lockout relay will prevent any signal flow. The key to this relay is if it will mechanically operate. Further, the lockout function only serves to prevent reclosing without a physical reset. For generator step up transformers this reclosing will occur when the unit is disconnected from the BES. There is no BES protection reason for testing this component.
Individual
Angela P Gaines
Portland General Electric Company
PGE still has concerns regarding the testing of the sensing mechanism of sudden pressure relays. Although some sudden pressure relays and newer Buchholz relays may be possible to test without draining oil or physically removing the Buchholz relay off the transformer, it does require taking the transformer out of service thereby reducing reliability of the BES. In cases where a Buchholz relay is required to be removed for testing, the added complexity would increase down time of critical transformers and introduce possibility that the relays are not reinstalled properly. Additionally newer microprocessor relays can provide sensitive sensing of internal transformer faults and these relays are routinely tested.
Individual
Bob Thomas
Illinois Municipal Electric Agency
Illinois Municipal Electric Agency believes the comments submitted by Florida Municipal Power Agency warrant specific attention by the SDT, and a PRC-005 WebEx to specifically address the appropriate scope/applicability for PRC-005. It is unfortunate this was not done before the current ballot.
Group

ACES Standards Collaborators
Jason Marshall
Yes
Yes. The previous proposed R6 requirement was clearly a Paragraph 81 requirement that was purely administrative in nature and provided little to no support for reliability. Thank you for removing it.
No
We agree with most of the changes to Table 5; however, we believe additional explanation is required in the last row regarding the “(See Table 2)” reference. What part of Table 2? Is something in Table 2 supposed to explain this last row further?
No
The data retention continues to be problematic in that it requires data to be retained longer than is required by the NERC Rules of Procedure. Section 3.1.4.2 of Appendix 4C – Compliance Monitoring and Enforcement Program states that the compliance audit will cover the period from the day after the last compliance audit to the end date of the current compliance audit. Given that many of the maximum maintenance intervals exceed audit periods (six years) for responsible entities, a responsible entity would be required to retain data previous to its last audit, which is not consistent with the Rules of Procedure. We suggest changing the data retention section such that the data only needs to be maintained since the last audit.
Yes
We agree with the deletions of the parts and sub-parts from the requirements. However, we do believe that is necessary to document in the implementation plan, a period of time for a responsible entity to become compliant should the standard become applicable to a new Automatic Reclosing Component particularly due to a change in the size of the largest unit in a Balancing Authority Area or Reserve Sharing Group. The implementation plan could be modeled after the “Implementation Plan for Newly Identified Critical Cyber Assets and Newly Registered Entities” developed by the CIP standard drafting team.
We have no new comments on the Supplementary Reference and FAQ.
(1) Applicability section 4.2.4 should be modified for clarity and to avoid potential conflicts with the definition of Remedial Action Schemes (RAS). The prior posting of the Remedial Action Scheme definition in Project 2010-05.2 – Special Protection Systems included the following statement: “these schemes are not Protection Systems.” This statement would conflict directly with section 4.4.2 that states “Protection Systems installed as a Remedial Action Scheme.” Even though current posting of the RAS definition has eliminated the clause causing the ambiguity, we suggest changing section 4.2.4 to simply be “Remedial Action Schemes” would avoid this ambiguity altogether and make PRC-005-X not dependent on changes that the other drafting team is making. (2) Thank you for the opportunity to comment.
Group
Duke Energy
Michael Lowman
Yes
No
Duke Energy questions the necessity of creating separate Tables for Sudden Pressure Relays and Automatic Reclosing Relays. We recommend the drafting team consider integrating the language found in the individual Tables in an effort to reduce the burden on the industry of monitoring and maintaining compliance with a number of different Tables.
Yes
Yes
Individual

Bill Temple
Northeast Utilities
Yes
Yes
Yes
Yes
Group
SERC Protection and Controls Subcommittee
David Greene
Yes
The redline to last posting does not show R6 being deleted; is the correct redline posted?
Yes
Yes
Yes
Please state in the R3 Rationale the fact that all Automatic Reclosing, and Sudden Pressure Relaying Components are newly identified within PRC-005 applicability upon the effective dates of PRC-005-3 and PRC-005-X, respectively. Automatic Reclosing, and Sudden Pressure Relaying Components are not being transitioned from PRC-005-1 et al.
none
1) Please state in the Implementation Plan the fact that all Automatic Reclosing, and Sudden Pressure Relaying Components are newly identified within PRC-005 applicability upon the effective dates of PRC-005-3 and PRC-005-X, respectively. Automatic Reclosing, and Sudden Pressure Relaying Components are not being transitioned from PRC-005-1 et al. 2) Given a change in the largest unit in a Balancing Authority Area or RSG and additional reclosing relays become applicable to the standard, by when do the additional reclosing relays need to be maintained, by the date of the change in the largest unit, or by the end of the maximal interval period for the subject component? Suggest clarity be added to the footnote 2 associated to 4.2.6.1 or adding a clarifying statements to “How do you determine the initial due dates for maintenance?” Section 8.2.1 of the FAQ document. The comments expressed herein represent a consensus of the views of the above-named members of the SERC EC Protection and Control Subcommittee only and should not be construed as the position of SERC Reliability Corporation, its board, or its officers.
Individual
Venona Greaff
Occidental Chemical Corporation
Individual
Karen Webb
City of Tallahassee
Yes

The City of Tallahassee (TAL) believes Sudden Pressure Relaying should not be added to PRC-005-X because they are not necessary for the “reliable operation” of the bulk power system as defined in statute. What is necessary for the reliable operation of the BPS are differential relays, overcurrent relays, etc., that are there to clear a major phase to ground or phase to phase fault that if left uncleared can cause instability. The purpose for a sudden pressure relay is primarily to monitor equipment health, e.g., detecting a turn-to-turn failure, not a phase to ground or phase to phase fault. If a sudden pressure relay fails to operate, there is no threat to BPS reliability since the differential relay / overcurrent relays are there if the fault develops into a major phase to ground or phase to phase fault. TAL believes that the use of sudden pressure relays are a good business practice, but we also believe that utilities should be free to adopt good business practice beyond the requirements of the standards, without the reverse incentives that being regulated, audited, etc., bring.
Individual
Catherine Wesley
PJM Interconnection
Yes
PJM supports the removal of R6 and will be submitting an affirmative ballot.
PJM urges the SDT to review and address PSEG’s concern regarding inclusion of a required maintenance interval for Sudden Pressure Relays (SPRs) that are utilized as a third level of transformer protection and are not a primary or backup transformer differential relay.
Group
SPP Standards Review Group
Shannon V. Mickens
Yes
Yes
Yes
Yes
no.
yes. During the webinar, when asked for clarification regarding changes in the largest unit as found in Footnote 2, the SDT Chair indicated that newly identified Automatic Reclosing Components would fall into the maintenance cycle as found in the applicable table for that specific component. While we concur with that interpretation, we have concerns that Footnote 2 gives the impression that those components would be subject to the standard on the date the change occurred and those components would have to be compliant on the date of the change. We suggest the SDT make the following addition to Footnote 2: The largest BES generating unit within the Balancing Authority Area or the largest generating unit within the Reserve Sharing Group, as applicable, is subject to change. As a result of such a change, the Automatic Reclosing Components subject to the standard could change effective on the date of such change. From that day forward, those components would then have to be maintained according to the maintenance cycle as found in the applicable table for that specific component.
Group
Bonneville Power Administration
Andrea Jessup
Yes

Yes
Yes
Yes
No.
Yes. BPA requests clarification on the following definition and the intent of the definition. BPA understands the definition was created before the inclusion of sudden pressure relays (which includes buchholz and sudden flow relays as well). Attachment A (PBM) the definition of Segment: "Segment – Components of a consistent design standard, or a particular model or type from a single manufacturer that typically share other common elements. Consistent performance is expected across the entire population of a segment. A segment must contain at least sixty (60) individual components." It appears that the intent is to monitor the segment of 60 for consistent performance to determine if it is acceptable to combine population segments. If this type of tracking is the intent and populations are tracked by manufacturer and model, is it also the intent to create components of a common application that typically share common elements, such as a mechanical buchholz device regardless of manufacturer? If there is a significant performance difference among manufacturers of a buchholz device it would be evident during the tracking process when the events are counted and the populations compared. If various application stresses and fatigue become the driving force for an item to fail, it is likely to be manufacturer independent and grouping by buchholz relay would be the best way to track performance. BPA's concern is that if the definition is tied to the manufacturer and model, many items that may have benefited from a performance based maintenance program will not be included due to the difficulty of having 60 components of a single manufacturer and model. As a result, less performance based maintenance will be done in favor of more time based maintenance, which does not appear to be the stated objective of the standard. BPA believes that there are other drivers of equipment reliability and that going simply by manufacturer make and model is too restrictive and almost forces the use of time based maintenance intervals. These time based maintenance intervals have been established by surveying utilities and taking the average maintenance interval of the surveyed utilities. BPA suggests it would be better to allow an alternate definition of Segment to include, for example, mechanical sudden pressure relays to be grouped as an item, provided the population has consistent performance across the population and provided the population is tracked by manufacturer and model. BPA believes this would allow performance based maintenance systems to be applied more broadly and would be more effective than using time based maintenance intervals. For example, provided an entity also tracks manufacturer and model and establishes consistent performance across the population, could an entity track the following groups as a population segment? 1. Mechanical Sudden Pressure Relay 2. Electronic Sudden Pressure Relay 3. Mechanical Buchholz Relay 4. Mechanical Sudden Flow Relay
Individual
Sergio Banuelos
Tri-State Generation and Transmission Association, Inc.
Yes
Tri-State understands and approves of the removal since it was a "check the box" requirement and didn't help the reliability of the BES. However, we wonder how the auditors are going to confirm that an entity requested and used the correct information in determining applicability for automatic reclosers. What is the SDT suggesting to address this?
Yes
Yes
Yes

Individual
Joshua Andersen
Salt River Project
Yes
Yes
Yes
Yes
Salt River Project suggests that sudden pressure relays are not necessary for the reliable operation of the Bulk-Power System. Faults that would trip the sudden pressure relays would also trip other relays used for protection of the assets. Salt River Project recommends the removal of sudden pressure relays from this standard and recommends that the other relays be updated where necessary. Additionally, a requirement for the sudden pressure relays may persuade entities to remove or inactivate them so they are not subject to the requirements in this standard.

Additional Comments:

Austin Energy
Thomas Standifur

Austin Energy supports the comments submitted by Florida Municipal Power Agency (FMPA), and add the following thought for the SDT's consideration. The purpose of the Sudden Pressure Relay should be considered in the applicability of the requirements. In instances where a Sudden Pressure Relay is employed to protect an entity owned asset from damage by removing the asset from operation prior, and where the relay is not employed to protect the reliability of the BES, the Sudden Pressure Relay should be excluded from the requirements of this standard. For instance, a Sudden Pressure Relay used to remove a piece of equipment from service to prevent severe equipment damage and not being used to protect the reliability of the BES should be excluded from the requirements of this standard.

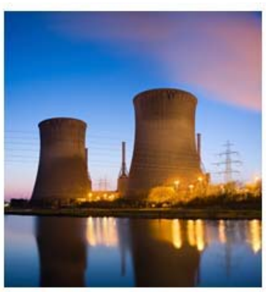
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Consideration of Comments

Project 2007-17.3 Protection System Maintenance and Testing (PRC-005-X)

October 20, 2014

RELIABILITY | ACCOUNTABILITY

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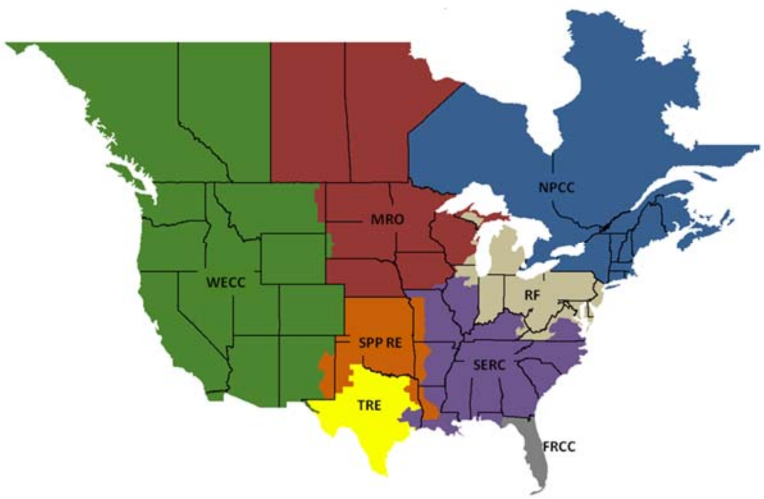
Preface

The North American Electric Reliability Corporation (NERC) is a not-for-profit international regulatory authority whose mission is to ensure the reliability of the bulk power system (BPS) in North America. NERC develops and enforces Reliability Standards; annually assesses seasonal and long-term reliability; monitors the BPS through system awareness; and educates, trains, and certifies industry personnel. NERC's area of responsibility spans the continental United States, Canada, and the northern portion of Baja California, Mexico. NERC is the electric reliability organization (ERO) for North America, subject to oversight by the Federal Energy Regulatory Commission (FERC) and governmental authorities in Canada. NERC's jurisdiction includes users, owners, and operators of the BPS, which serves more than 334 million people.

The North American BPS is divided into several assessment areas within the eight Regional Entity (RE) boundaries, as shown in the map and corresponding table below.



FRCC	Florida Reliability Coordinating Council
MRO	Midwest Reliability Organization
NPCC	Northeast Power Coordinating Council
RF	ReliabilityFirst
SERC	SERC Reliability Corporation
SPP-RE	Southwest Power Pool Regional Entity
TRE	Texas Reliability Entity
WECC	Western Electricity Coordinating Council

Introduction

The Project 2007-17.3 drafting team thanks everyone who submitted comments on draft 2 of the PRC-005-X standard. Each comment received has been reviewed and given careful consideration by the drafting team.

This standard was posted for a 45-day public comment period from July 30, 2014, through September 12, 2014. NERC asked stakeholders to provide feedback on the standard and associated documents through a special electronic comment form. There were 47 sets of responses, including comments from approximately 116 people from approximately 82 companies, representing all 10 Industry Segments.

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

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

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

Consideration of Comments

Sudden Pressure Relaying

Some comments received asserted that Sudden Pressure Relaying does not impact the reliable operation of the Bulk Electric System; therefore, should not be included in PRC-005-X. Below is additional background regarding the FERC directive and why Sudden Pressure Relaying are being added to PRC-005-X.

FERC NOPR Proposing to Approve PRC-005 Interpretation

In FERC's Notice of Proposed Rulemaking (NOPR), the Commission proposed to accept NERC's proposed interpretation of Reliability Standard PRC-005-1 Requirement R1. However, the Commission stated that the proposed interpretation highlights a gap in the required Protection System maintenance and testing pursuant to Requirement R1 of PRC-005-1. To prevent a gap in reliability, FERC stated that any component that detects any quantity needed to take an action, or that initiates any control action (initial tripping, reclosing, lockout, etc.) affecting the reliability of the Bulk-Power System should be included as a component of a Protection System. Accordingly, to address FERC's concern, pursuant to section 215 (d) (5) of the Federal Power Act, FERC proposed to direct NERC to develop a modification to the Reliability Standard to include *any component or device that is designed to detect defective lines or apparatuses or other power system conditions of an abnormal or dangerous nature and to initiate appropriate control circuit actions*.

NERC NOPR Comments (pgs. 6-7)

"Regarding FERC's proposed directive to include in the Reliability Standard any device, including auxiliary and backup protection devices, that is designed to sense or take action against any abnormal system condition that will affect reliable operation, NERC states that it understands FERC's concerns related to protective relays that do not respond to electrical quantities and agrees that sudden pressure relays which trip for fault conditions should be maintained in accordance with NERC Reliability Standard requirements. However, NERC is not aware of any existing documents that establish a technical basis for either minimum maintenance activities or maximum maintenance intervals for these devices. NERC expressed concern that the scope of this proposed directive is so broad that any device that is installed on the bulk power system to monitor conditions in any fashion may be included. In fact, many of these devices are advisory in nature and should not be reflected within NERC Standards if they do not serve a necessary reliability purpose. NERC therefore proposed to develop, either independently or in association with other technical organizations such as IEEE, one or more technical documents which:

i. Describe the devices and functions (to include sudden pressure relays which trip for fault conditions) that should address FERC's concern; and

ii. Propose minimum maintenance activities for such devices and maximum maintenance intervals, including the technical basis for each.

These technical documents will address *those protective relays that are necessary for the reliable operation of the bulk power system* and will allow for differentiation between protective relays that detect faults from other devices that monitor the health of the individual equipment and are advisory in nature (e.g., oil temperature). Following development of the above-referenced document(s), NERC would propose a new or revised standard (e.g., PRC-005) using the NERC Reliability Standards development process to include maintenance of such devices, including establishment of minimum maintenance activities and maximum maintenance intervals. NERC did not believe it is necessary for the Commission to issue a directive to address this issue. Rather, NERC proposed to add this issue to the reliability standards issues database for inclusion in the list of issues to address the next time the PRC-005 standard is revised."

FERC Order No. 758 (Para. 12-15)[2]
[Summary of NERC's NOPR comments in P 12-14 have been omitted here for brevity]
"15. The Commission accepts NERC's proposal, and directs NERC to file, within sixty days of publication of this Final Rule, a schedule for informational purposes regarding the development of the technical documents referenced above, including the identification of devices that are designed to sense or take action against any abnormal system condition that will affect reliable operation. NERC shall include in the informational filing a schedule for the development of the changes to the standard that NERC stated it would propose as a result of the above-referenced documents. NERC should update its schedule when it files its annual work plan."

NERC April 12, 2012 Informational Filing[3]
Summary: NERC's filing included a schedule for preparing the necessary technical documents through the SPCS and a schedule for the SPCS work. However, the filing did not include a schedule for the standard development as FERC had required. FERC noted that NERC should update its schedule for the standard development when it files its annual work plan. NERC's Reliability Standards Development Plan (RSDP) has included the development work schedule. Because NERC filed the item as "informational", FERC did not issue an order accepting or rejecting the filing as it would have done for a "compliance" filing. NERC submitted a further informational filing in July 2012 addressing reclosing relays, but did not include any additional discussion of sudden pressure relays.

Sudden Pressure Relays and Other Devices that Respond to Non-Electrical Quantities
NERC Special Protection and Control Subcommittee (SPCS) Input for Standard Development in Response to FERC Order No. 758 – December 2013.

In developing this report, the SPCS evaluated all devices on the IEEE list of device numbers to identify which devices that respond to non-electrical quantities may impact reliable operation of the Bulk-Power System. As a result of this analysis, the SPCS concludes the only devices responding to non-electrical quantities that should be included in the applicability of PRC-005 are sudden pressure relays utilized in a tripping function. When applied in a tripping function, these devices initiate actions to clear faults to support reliable operation of the Bulk-Power System. The other devices evaluated respond to abnormal equipment conditions and take action to protect equipment from mechanical or thermal damage, or premature loss of life, rather than for the purpose of initiating fault clearing or mitigating an abnormal system condition to support reliable operation of the Bulk-Power System.

From SPCS Report:

Table 1: Classification of Devices		
Initiate Actions to Clear Faults or Mitigate Abnormal System Conditions to Support Reliable Operation of the Bulk-Power System	**Initiate Action for Abnormal Equipment Conditions for Purposes other than Supporting Reliable Operation of the Bulk-Power System**	**Monitor the Health of Individual Equipment and Provide Information that is Advisory in Nature**
Sudden Pressure (63) (when utilized in a trip application)	• Overspeed Device (12) • Underspeed Device (14) • Apparatus Thermal Device (26) • Flame Detector (28) • Bearing Protective Device (38)	• Apparatus Thermal Device (26) • Bearing Protective Device (38) • Mechanical Condition Monitor (39) • Atmospheric Condition Monitor (45)

[2] *Interpretation of Protection System Reliability Standard*, 138 FERC ¶ 61,094 (Order No. 748) (2012)
http://www.nerc.com/files/Order_Interp_Protection_Sys_RS_2011.2.3.pdf
[3] Informational Filing in Compliance with Order No. 758 – Interpretation of Protection System Reliability Standard, FERC Docket No. RM10-5-000, (2012)
http://www.nerc.com/FilingsOrders/us/NERC%20Filings%20to%20FERC%20DL/Order%20758%20Letter%20Filing_complete.pdf

	• Mechanical Condition Monitor (39) • Atmospheric Condition Monitor (45) • Machine or Transformer Thermal Relay (49) • Density Switch or Sensor (61) • Pressure Switch (63) (other than sudden pressure relays utilized in trip application) • Level Switch (71)	• Machine or Transformer Thermal Relay (49) • Density Switch or Sensor (61) • Pressure Switch (63) (other than sudden pressure relays utilized in trip application) • Level Switch (71)

Following the issuance of the report by the Planning Committee, Project 2007-17.3 was proposed for the 2014-2016 NERC Reliability Standards Development Plan (RSDP), and adopted by the NERC Board. The SDT added Sudden Pressure Relaying to PRC-005-X in accordance with the technical recommendations from the SPCS report.

An additional concern was expressed that sudden pressure relays represent third level transformer protection; primary and backup transformer differential relays would isolate the transformer in case of a fault. The drafting team thanks you for your comment. All Sudden Pressure Relaying applicable under Facilities Section 4.2, regardless of what level of protection, are subject to the requirements of the standard.

Definitions

One commenter provided suggestions on the definition for Countable Event. The drafting team thanks you for your comment. However, at this time changes to the Countable Event definition are outside the scope of project 2007-17.3.

Another commenter requested clarification on the defined NERC Glossary term Segment. The entity's "concern is that if the definition is tied to the manufacturer and model, many items that may have benefited from a performance based maintenance program will not be included due to the difficulty of having 60 components of a single manufacturer and model. As a result, less performance based maintenance will be done in favor of more time based maintenance, which does not appear to be the stated objective of the standard. BPA believes that there are other drivers of equipment reliability and that going simply by manufacturer make and model is too restrictive and almost forces the use of time based maintenance intervals. These time based maintenance intervals have been established by surveying utilities and taking the average maintenance interval of the surveyed utilities. BPA suggests it would be better to allow an alternate definition of Segment to include, for example, mechanical sudden pressure relays to be grouped as an item, provided the population has consistent performance across the population and provided the population is tracked by manufacturer and model. BPA believes this would allow performance based maintenance systems to be applied more broadly and would be more effective than using time based maintenance intervals. For example, provided an entity also tracks manufacturer and model and establishes consistent performance across the population, could an entity track the following groups as a population segment? 1. Mechanical Sudden Pressure Relay 2. Electronic Sudden Pressure Relay 3. Mechanical Buchholz Relay4. Mechanical Sudden Flow Relay." The drafting team thanks you for your comment. The Segment definition aligns with the drafting team's intent. The definition states: Segment – Components of a consistent design standard, or a particular model or type from a single manufacturer that typically share other common elements. Consistent performance is expected across the entire population of a Segment. A Segment must contain at least sixty (60) individual Components.

Applicability Section

One commenter stated that "(1) Applicability section 4.2.4 should be modified for clarity and to avoid potential conflicts with the definition of Remedial Action Schemes (RAS). The prior posting of the Remedial Action Scheme definition in Project 2010-05.2 "Special Protection Systems included the following statement: these schemes are not Protection Systems. This statement would conflict directly with section 4.4.2 that states Protection Systems installed as a Remedial Action Scheme. Even though current posting of the RAS definition has eliminated the clause causing the ambiguity, we suggest changing section 4.2.4 to simply be Remedial Action Scheme would avoid this ambiguity altogether and make PRC-005-X not dependent on changes that the other drafting team is making." The drafting team thanks you for your comment. The Project 2010-05.2 Standard Drafting Team (SDT) is aware of this concern and made the change to the RAS definition to resolve this conflict.

PRC-005-X Requirements

Comments were received regarding Requirements R3, R4 and the deleted R6, which are summarized and addressed below.

Requirement R3 and R4

A few commenters questioned the clarity regarding the removal of subparts from Requirement R3 and R4. The drafting team thanks the commenters, but disagrees and contends Requirement R3 and R4 are clear.

Several commenters expressed concern regarding the maintenance of Automatic Reclosing Components that become newly applicable due to changes in the largest BES generating unit in the BA/RSG. The drafting team notes that the entity only needs to complete the maintenance by the end of the established interval within Table 4, the shortest of which is six years from the time the change in the largest generating unit was made. Additionally, a frequently asked question has been developed and inserted into section 15.8.1 of the "Supplementary Reference and Frequently Asked Questions" to clarify this intent.

Requirement R6

A few comments stated that the Balancing Authority (BA) should be held accountable for providing the information to the Transmission Owner (TO), Generator Owner (GO), or Distribution Provider (DP) of the largest generating unit. Following discussion, the drafting team determined that the Automatic Reclosing equipment "owner" is responsible for identifying Automatic Reclosing Components that must be included in their PSMP. Therefore, the owner is responsible for obtaining the largest generating unit information. If the BA does not provide the appropriate information requested, the owner should contact its Regional Entity (RE) for assistance in acquiring the appropriate information.

Another commenter questioned what an auditor will request during an audit. The owner should be able to provide a call log or an email to the BA requesting information regarding the largest generating unit. Additionally, the Balancing Authority or RSG could post the largest generating unit information, if it chooses to do so. The entity could complete a "print screen" and provide that as evidence to the auditor.

A few additional commenters noted that Requirement R6 did not show up in the redline version of PRC-005-X draft two. The drafting team notes that the version posted was the accurate and the redline of Requirement R6 was erroneously removed.

Additional comments support the removal of Requirement R6.

Tables

Table 5

Some commenters expressed concern regarding confusion of the wording in the note in the title box of Table 5. It refers to Table 1-5, yet in the title box for Table 1-5 it states that Sudden Pressure Relaying is excluded. The drafting team thanks you for your comments. The items in Table 5 are for components that are unique to Sudden Pressure Relaying.

Another commenter states that “it is not clear in Table 5 if verification of the pressure or flow sensing mechanism is operable includes a test that the fault pressure relay when activated actually operates the auxiliary relay, elctromechanical lockout device or circuit breaker or other interrupting device to which it is connected? Is it intended that this test is a part of the control circuity test of Table 5? It is recommended that a clarification be made for this issue either in Table 5 or the reference document.” The drafting team thanks you for your comment. The maintenance activities for Sudden Pressure Relaying must be performed whether as discrete activities or via an overall functional test.

A few comments were received recommending fault pressure relays be placed on a 12 calendar year maintenance interval instead of a six year maintenance interval. The drafting team thanks you for your comments. The frequency of the testing is set to align with the NERC SPCS report responding to FERC Order 758.

Another commenter stated that “errors in the text of Table 5 remain. It fails to differentiate the maintenance interval between monitored and un-monitored elements. The suggested change is: Change Component Attributes from Control circuitry associated with Sudden Pressure Relaying to Unmonitored control circuitry associated with Sudden Pressure Relaying from the fault pressure relay to the interrupting device trip coil(s).” The drafting team thanks you for your comment and notes that the word "unmonitored" has been added to Table 5 for clarification.

An additional commenter states “the note below the title of Table 5 implies to us that if such Components differ from those in Table 1-5, they are outside Applicability in both PRC-005-2 and PRC-005-3. Is that correct?” The drafting team thanks you for your comment. It was previously stated in the Supplementary reference and FAQ that PRC-005-2 and PRC-005-3 included the sudden pressure relaying control circuitry; however, Table 5 of PRC-005-X makes it clear.

An additional commenter states “we feel the current draft of Table 5 is too broad in the use of the term, Any Fault Pressure Relay. The SCPS report conclusion (Page 31) indicates, where the device is installed to respond to rapid pressure rise in facilities described in the applicability section of Reliability Standard PRC-005, and configured to take action to initiate fault clearing to support reliable operation of the Bulk Power System, it should be included as a device to be maintained and tested. Since many SPR devices are installed simply to protect equipment from excessive loss of life (or simply indication) rather than to provide fault detection or clearing for the BES, the mandatory inclusion of Any Fault Pressure Relay to the PSMP via Table 5 falls outside the intended scope of the SPCS report. Additional validation of this interpretation is gained from the previous sentence in the SPCS document: Where this device is applied to respond to abnormal equipment conditions, it takes action to protect the equipment from excessive loss of life or to indicate unavailability of service, rather than for the purpose of initiating fault clearing or mitigating an abnormal system condition to support reliable operation of the Bulk-Power System. We feel if the device is not providing support for reliable operation of the Bulk Power System it should be excluded from the PSMP.” The drafting team thanks you for your comments. The scope is limited by the Sudden Pressure Relaying definition:

> **“Sudden Pressure Relaying** – A system that trips an interrupting device(s) to isolate the equipment it is monitoring and includes the following Components:
>
> - Fault pressure relay – a mechanical relay or device that detects rapid changes in gas pressure, oil pressure, or oil flow that are indicative of Faults within liquid-filled, wire-wound equipment

- Control circuitry associated with a fault pressure relay."

Another commenter expressed that they "disagree with the handling of sudden pressure relays. The added requirement for electrical testing of the lockout relay should be deleted. Typically the physical separation of the pathway by the lockout relay will prevent any signal flow. The key to this relay is if it will mechanically operate. Further, the lockout function only serves to prevent reclosing without a physical reset. For generator step up transformers this reclosing will occur when the unit is disconnected from the BES. There is no BES protection reason for testing this component." The drafting team thanks you for your comments. If the lockout is not used for tripping there is no requirement in Table 5 to test it.

A comment was received regarding the Table 2 comment in the title part of Table 5. The drafting team thanks you for your comments. Table 2 discusses the maintenance on the monitoring path if an entity wishes to use monitoring to extend or defer physical maintenance and also stipulates that the monitoring must be conveyed to a location where corrective action can be initiated.

A commenter recommended the drafting team consider integrating the language found in the individual Tables in an effort to reduce the burden on the industry of monitoring and maintaining compliance with a number of different Tables. The drafting team thanks you for your comment. Table 1-1 through1-5, and Table 3 apply to Protection System components; Automatic Reclosing is Table 4 and Sudden Pressure Relaying is Table 5, and monitoring attributes is Table 2. The drafting team has considered various options and concluded that the way the tables have been laid out is clear.

An additional comment provided states: "The title box for Table 1-5 refers to Automatic Reclosing (see Table 4). There is no Table 4. It should be reworded to read Tables 4-1 through 4-2 as it reads in the title box for Table 2.The many tables and cross references between the tables in the standard make the standard difficult to use. Reorganizing the tables, possibly having one table per component type with component attributes listed should be considered." The drafting team thanks you for your comment. Reference to Table 4 within Table 1-5 includes all subparts of Table 4.

One commenter stated: "we understand the use of 'pressure or flow sensing' within the first Table 5 Maintenance Activity is within the context of the PRC-005-X Fault pressure relay definition and therefore does not include other types of pressure or oil flow devices found on transformers. Correct?" The drafting team thanks you for your comment. The above stated is correct.

Data Retention

A commenter commented regarding the terms "data retention" and "evidence retention" within the standard. The drafting team thanks you for your comment. The terms data retention and evidence retention are used interchangeably.

One comment stated that "Requirement R5 related to unresolved maintenance issues only applies when such an event occurs and that may not be associated with a particular periodic maintenance activity. It would seem more appropriate to retain records on the instances of unresolved maintenance issues that occurred since the last audit." The drafting team thanks you for your comment. Updated Requirement R5 evidence retention language has been added to the Evidence Retention section for clarification.

A few commenters expressed concern regarding the data retention requiring data to be retained longer than the current audit cycle for PRC-005. The drafting team thanks you for your comments. The evidence retained from the last maintenance activity is used to verify compliance with required maintenance intervals that exceed the audit cycle.

Implementation Plan

Several commenters expressed concern regarding the maintenance of Automatic Reclosing Components that become newly applicable due to changes in the largest BES generating unit in the BA/RSG. The drafting team notes that the entity only needs to complete the maintenance by the end of the established interval within Table 4, the shortest of which is six years from the time the change in the largest generating unit was made. Additionally, a frequently asked question has been developed and inserted into section 15.8.1 of the "Supplementary Reference and Frequently Asked Questions" to clarify this intent.

Footnote 2

One commenter expressed concern that "Footnote 2 gives the impression that those components would be subject to the standard on the date the change occurred and those components would have to be compliant on the date of the change. We suggest the SDT make the following addition to Footnote 2: The largest BES generating unit within the Balancing Authority Area or the largest generating unit within the Reserve Sharing Group, as applicable, is subject to change. As a result of such a change, the Automatic Reclosing Components subject to the standard could change effective on the date of such change. From that day forward, those components would then have to be maintained according to the maintenance cycle as found in the applicable table for that specific component. The drafting team thanks you for your comment. The date of the change of the largest BES generating unit serves as the starting point for applicability of the standard and the intervals established in Table 4. A frequently asked question has been developed and can be located in section 15.8.1.

Supplementary Reference and Frequently Asked Questions Document

One commenter stated: "Regarding the sync-check relays mentioned in 2.4.1 Frequently Asked Questions: because their operation is reliant upon voltage inputs, sync-check relay maintenance must be addressed in the tables, specifically maintenance done with voltages applied. Table 4-2(b) addresses control circuit paths, but verifying a control circuit path could be done by manually blocking contacts closed." The drafting team thanks you for your comment. Sync-check relays are not within the scope of this standard unless they are a part of a RAS. If part of a RAS they must be maintained according to Table 1.

Another commenter expressed that "pressure Relief Device (PRD) works on absolute pressure threshold. Currently these is no methodology to verify PRD sensing mechanism operation simulating required pressure. Can the drafting team an answer in the FAQ to guide us. Should PRD's not belong to the sudden pressure relay category?" The drafting team thanks you for your comment. The drafting team references the Sudden Pressure Relaying definition. PRD's are not included within the definition of Sudden Pressure Relays. See section 2.4.1 of the "Supplementary Reference and FAQ."

Additional Comment Clarification

PRC-005-4 | October 27, 2014

One commenter reached out to the Standard Drafting Team (SDT) to obtain additional explanation regarding its submitted comments and the accompanying SDT response. Following the discussion, the SDT prepared additional text to more fully respond. This response is provided below. As always, the SDT thanks stakeholders for your comments.

A comment received expressed concern regarding the Applicability Section for Facilities (4.2.1) and that it is too broad due to the inclusion of the capitalized term "Fault" and how that term is defined in the NERC Glossary. The concern stemmed from broken wires and intermittent connections being included as examples in the NERC Glossary definition for Fault, which was perceived to broaden the term to include potential events that would have little to no reliability impact to the BES, such as turn-to-turn faults in wound electrical apparatus. The commenter further stated that if the glossary term only referenced "short circuit", then this would not be a problem. However, the technical subject matter experts (SMEs) on the project, including SMEs beyond drafting team members, noted that a turn-to-turn fault in wound electrical apparatus is a short circuit, and therefore would be included even if the term were limited to short circuits. Additionally, sudden pressure relays will not respond to open circuits (broken wires), so the inclusion of this example in the definition does not have an impact on sudden pressure relays. Therefore, the use of Fault does not expand the scope. The comment also recommended limiting the applicability to "Relays that are installed as the primary or back-up relay for the purpose of detecting phase-to-ground or phase-to-phase short circuit on the BES." The SDT notes that all sudden pressure relays detect these types of short circuits. Consistent with the SPCS report, the SDT has included all sudden pressure relays utilized in a tripping function, as initiating fault clearing for these types of short circuits supports reliable operation of the Bulk-Power System.

An additional comment received expressed concern that the addition of the term "oil flow" to the definition of "Fault Pressure Relay," includes Buchholz relays in the definition of Sudden Pressure Relaying. The comment suggested this inclusion is inconsistent with the SPCS report; however, the SPCS report notes that "Order No. 758 used the term sudden pressure relays, which the SPCS has interpreted to refer to the general class of relays responding to pressure, including sudden pressure, rapid pressure rise, and Buchholz relays." The SDT addressed this on pages 12 and 13 of the Supplementary Reference and Frequently Asked Questions Document. "What type of devices are classified as fault pressure relay? There are three main types of fault pressure relays; rapid gas pressure rise, rapid oil pressure rise, and rapid oil flow devices. Rapid gas pressure devices monitor the pressure in the space above the oil (or other liquid), and initiate tripping action for a rapid rise in gas pressure resulting from the rapid expansion of the liquid caused by a fault. The sensor is located in the gas space. Rapid oil pressure devices monitor the pressure in the oil (or other liquid), and initiate tripping action for a rapid pressure rise caused by a fault. The sensor is located in the liquid. Rapid oil flow devices ("Buchholz") monitor the liquid flow between a transformer/reactor and its conservator. Normal liquid flow occurs continuously with ambient temperature changes and with internal heating from loading and does not operate the rapid oil flow device. However, when an internal arc happens a sudden expansion of liquid can be monitored as rapid liquid flow from the transformer into the conservator resulting in actuation of the rapid oil flow device." Therefore, only the rapid flow sensor of the Buchholz, when used for tripping, is within the applicability; the gas accumulation or oil leak detection features of Buchholz devices are not in scope.

Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Development Steps Completed

1. SAR posted for comment February 13, 2014 – March 14, 2014.
2. The draft standard was posted for a 45-day concurrent comment and ballot period of April 17, 2014–June 3, 2014.
3. The draft standard was posted for a 45-day additional comment and ballot period of July 30 – September 12, 2014

Description of Current Draft

The Protection System Maintenance and Testing Standard Drafting Team (PSMT SDT) is posting draft 3 of PRC-005-4 for a 10-day final ballot.

This draft contains the technical content of the standard. A parallel effort in the Project 2014-01, Standards Applicability for Dispersed Generation Resources, will post an applicability change to PRC-005-2 and PRC-005-3 for comment and ballot.

Anticipated Actions	Anticipated Date
45-day Formal Comment Period with Parallel Ballot	April 17 – June 2, 2014
45-day Additional Formal Comment Period with Parallel Ballot (if necessary)	July 30 – September 12, 2014
Final ballot	October 20, 2014
BOT adoption	November 13, 2014

Definitions of Terms Used in Standard

This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the Reliability Standards Glossary of Terms (Glossary) are not repeated here. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, this defined term will be removed from the individual standard and added to the Glossary.

Protection System Maintenance Program (PSMP) — An ongoing program by which Protection System, Automatic Reclosing, and Sudden Pressure Relaying Components are kept in working order and proper operation of malfunctioning components is restored. A maintenance program for a specific Component includes one or more of the following activities:

- Verify — Determine that the Component is functioning correctly.
- Monitor — Observe the routine in-service operation of the Component.
- Test — Apply signals to a Component to observe functional performance or output behavior, or to diagnose problems.
- Inspect — Examine for signs of Component failure, reduced performance or degradation.
- Calibrate — Adjust the operating threshold or measurement accuracy of a measuring element to meet the intended performance requirement.

See Section A.6, Definitions Used in this Standard, for additional definitions that are new or modified for use within this standard.
When this standard has received ballot approval, the text boxes will be moved to the Application Guidelines Section of the Standard.

A. Introduction

1. **Title: Protection System, Automatic Reclosing, and Sudden Pressure Relaying Maintenance**
2. **Number: PRC-005-4**
3. **Purpose:** To document and implement programs for the maintenance of all Protection Systems, Automatic Reclosing, and Sudden Pressure Relaying affecting the reliability of the Bulk Electric System (BES) so that they are kept in working order.

Rationale for Applicability Section: This section does not reflect the applicability changes that will be proposed by the Project 2014-01 Standards Applicability for Dispersed Generation Resources standards drafting team. The changes in this posted version and those being made by the Project 2014-01 standards drafting team do not overlap.

Additionally, to align with ongoing NERC standards development in Project 2010-05.2: Special Protection Systems, the term “Special Protection Systems” in PRC-005-4 was replaced by the term “Remedial Action Schemes.” These terms are synonymous in the NERC Glossary of Terms.

4. **Applicability:**

4.1. Functional Entities:

4.1.1 Transmission Owner

4.1.2 Generator Owner

4.1.3 Distribution Provider

4.2. Facilities:

4.2.1 Protection Systems and Sudden Pressure Relaying that are installed for the purpose of detecting Faults on BES Elements (lines, buses, transformers, etc.)

4.2.2 Protection Systems used for underfrequency load-shedding systems installed per ERO underfrequency load-shedding requirements.

4.2.3 Protection Systems used for undervoltage load-shedding systems installed to prevent system voltage collapse or voltage instability for BES reliability.

4.2.4 Protection Systems installed as a Remedial Action Scheme (RAS) for BES reliability.

4.2.5 Protection Systems and Sudden Pressure Relaying for generator Facilities that are part of the BES, including:

4.2.5.1 Protection Systems that act to trip the generator either directly or via lockout or auxiliary tripping relays.

4.2.5.2 Protection Systems and Sudden Pressure Relaying for generator step-up transformers for generators that are part of the BES.

4.2.5.3 Protection Systems and Sudden Pressure Relaying for transformers connecting aggregated generation, where the aggregated generation is part of the BES (e.g., transformers connecting facilities such as wind-farms to the BES).

4.2.5.4 Protection Systems and Sudden Pressure Relaying for station service or excitation transformers connected to the generator bus of generators which are part of the BES, that act to trip the generator either directly or via lockout or tripping auxiliary relays.

4.2.6 Automatic Reclosing[1], including:

[1] Automatic Reclosing addressed in Section 4.2.6.1 and 4.2.6.2 may be excluded if the equipment owner can demonstrate that a close-in three-phase fault present for twice the normal clearing time (capturing a minimum trip-close-trip time delay) does not result in a total loss of gross generation in the Interconnection exceeding the gross capacity of the largest relevant BES generating unit where the Automatic Reclosing is applied.

4.2.6.1 Automatic Reclosing applied on the terminals of Elements connected to the BES bus located at generating plant substations where the total installed gross generating plant capacity is greater than the gross capacity of the largest BES generating unit within the Balancing Authority Area or, if a member of a Reserve Sharing Group, the largest generating unit within the Reserve Sharing Group. [2]

4.2.6.2 Automatic Reclosing applied on the terminals of all BES Elements at substations one bus away from generating plants specified in Section 4.2.6.1 when the substation is less than 10 circuit-miles from the generating plant substation.

4.2.6.3. Automatic Reclosing applied as an integral part of an RAS specified in Section 4.2.4.

5. **Effective Date:** See Implementation Plan

6. **Definitions Used in this Standard:**

Automatic Reclosing – Includes the following Components:

- Reclosing relay
- Control circuitry associated with the reclosing relay.

Sudden Pressure Relaying – A system that trips an interrupting device(s) to isolate the equipment it is monitoring and includes the following Components:

- Fault pressure relay – a mechanical relay or device that detects rapid changes in gas pressure, oil pressure, or oil flow that are indicative of Faults within liquid-filled, wire-wound equipment
- Control circuitry associated with a fault pressure relay

Unresolved Maintenance Issue – A deficiency identified during a maintenance activity that causes the Component to not meet the intended performance, cannot be corrected during the maintenance interval, and requires follow-up corrective action.

Segment – Components of a consistent design standard, or a particular model or type from a single manufacturer that typically share other common elements. Consistent performance is expected across the entire population of a Segment. A Segment must contain at least sixty (60) individual Components.

[2] The largest BES generating unit within the Balancing Authority Area or the largest generating unit within the Reserve Sharing Group, as applicable, is subject to change. As a result of such a change, the Automatic Reclosing Components subject to the standard could change effective on the date of such change.

Component Type –

- Any one of the five specific elements of a Protection System.
- Any one of the two specific elements of Automatic Reclosing.
- Any one of the two specific elements of Sudden Pressure Relaying.

Rationale for the deletion of part of the definition of Component: The SDT determined that it was explanatory in nature and adequately addressed in the Supplementary Reference and FAQ Document.

Component – Any individual discrete piece of equipment included in a Protection System, Automatic Reclosing, or Sudden Pressure Relaying.

Countable Event – A failure of a Component requiring repair or replacement, any condition discovered during the maintenance activities in Tables 1-1 through 1-5, Table 3, Tables 4-1 through 4-2, and Table 5, which requires corrective action or a Protection System Misoperation attributed to hardware failure or calibration failure. Misoperations due to product design errors, software errors, relay settings different from specified settings, Protection System Component, Automatic Reclosing, or Sudden Pressure Relaying configuration or application errors are not included in Countable Events.

B. Requirements and Measures

R1. Each Transmission Owner, Generator Owner, and Distribution Provider shall establish a Protection System Maintenance Program (PSMP) for its Protection Systems, Automatic Reclosing, and Sudden Pressure Relaying identified in Section 4.2, Facilities. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning*]

The PSMP shall:

1.1. Identify which maintenance method (time-based, performance-based per PRC-005 Attachment A, or a combination) is used to address each Protection System, Automatic Reclosing, and Sudden Pressure Relaying Component Type. All batteries associated with the station dc supply Component Type of a Protection System shall be included in a time-based program as described in Table 1-4 and Table 3.

1.2. Include the applicable monitored Component attributes applied to each Protection System, Automatic Reclosing, and Sudden Pressure Relaying Component Type consistent with the maintenance intervals specified in Tables 1-1 through 1-5, Table 2, Table 3, Table 4-1 through 4-2, and Table 5 where monitoring is used to extend the maintenance intervals beyond those specified for unmonitored Protection System, Automatic Reclosing, and Sudden Pressure Relaying Components.

M1. Each Transmission Owner, Generator Owner and Distribution Provider shall have a documented Protection System Maintenance Program in accordance with Requirement R1.

For each Protection System, Automatic Reclosing, and Sudden Pressure Relaying Component Type, the documentation shall include the type of maintenance method applied (time-based, performance-based, or a combination of these maintenance methods), and shall include all batteries associated with the station dc supply Component Types in a time-based program as described in Table 1-4 and Table 3. (Part 1.1)

For Component Types that use monitoring to extend the maintenance intervals, the responsible entity(s) shall have evidence for each Protection System, Automatic Reclosing, and Sudden Pressure Relaying Component Type (such as manufacturer's specifications or engineering drawings) of the appropriate monitored Component attributes as specified in Tables 1-1 through 1-5, Table 2, Table 3, Table 4-1 through 4-2, and Table 5. (Part 1.2)

R2. Each Transmission Owner, Generator Owner, and Distribution Provider that uses performance-based maintenance intervals in its PSMP shall follow the procedure established in PRC-005 Attachment A to establish and maintain its performance-based intervals. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

M2. Each Transmission Owner, Generator Owner, and Distribution Provider that uses performance-based maintenance intervals shall have evidence that its current performance-based maintenance program(s) is in accordance with Requirement R2, which may include, but is not limited to, Component lists, dated maintenance records, and dated analysis records and results.

Rationale for R3 Part 3.1: In the last posting, the SDT included language in the standard that was originally in the implementation plan that required completion of maintenance activities within three years for newly-identified Automatic Reclosing Components following a notification under Requirement R6, which has been removed. After further discussion, the SDT determined that a separate shorter timeframe for maintenance of newly-identified Automatic Reclosing Components created unnecessary complication within the standard. The SDT agreed that entities should be responsible for maintaining the Automatic Reclosing Components subject to the standard, whether existing, newly added or newly within scope based on a change in the largest generating unit in the BA or, if a member of a Reserve Sharing Group, the largest generating unit within the Reserve Sharing Group according to the timeframes in the maintenance tables. Therefore, 3.1 and its subparts have been removed and have not been reinserted into the implementation plan.

R3. Each Transmission Owner, Generator Owner, and Distribution Provider that utilizes time-based maintenance program(s) shall maintain its Protection System, Automatic Reclosing, and Sudden Pressure Relaying Components that are included within the time-based maintenance program in accordance with the minimum maintenance activities and maximum maintenance intervals prescribed within Tables 1-1 through

1-5, Table 2, Table 3, Table 4-1 through 4-2, and Table 5. *[Violation Risk Factor: High] [Time Horizon: Operations Planning]*

M3. Each Transmission Owner, Generator Owner, and Distribution Provider that utilizes time-based maintenance program(s) shall have evidence that it has maintained its Protection System, Automatic Reclosing, and Sudden Pressure Relaying Components included within its time-based program in accordance with Requirement R3. The evidence may include, but is not limited to, dated maintenance records, dated maintenance summaries, dated check-off lists, dated inspection records, or dated work orders.

Rationale for R4 Part 4.1: In the last posting, the SDT included language in the standard that was originally in the implementation plan that required completion of maintenance activities within three years for newly-identified Automatic Reclosing Components following a notification under Requirement R6, which has been removed. After further discussion, the SDT determined that a separate shorter timeframe for maintenance of newly-identified Automatic Reclosing Components created unnecessary complication within the standard. The SDT agreed that entities should be responsible for maintaining the Automatic Reclosing Components subject to the standard, whether existing, newly added or newly within scope based on a change in the largest generating unit in the BA or, if a member of a Reserve Sharing Group, the largest generating unit within the Reserve Sharing Group according to the timeframes in the maintenance tables. Therefore, 4.1 and its subparts have been removed and have not been reinserted into the implementation plan.

R4. Each Transmission Owner, Generator Owner, and Distribution Provider that utilizes performance-based maintenance program(s) in accordance with Requirement R2 shall implement and follow its PSMP for its Protection System, Automatic Reclosing, and Sudden Pressure Relaying Components that are included within the performance-based program(s). *[Violation Risk Factor: High] [Time Horizon: Operations Planning]*

M4. Each Transmission Owner, Generator Owner, and Distribution Provider that utilizes performance-based maintenance intervals in accordance with Requirement R2 shall have evidence that it has implemented the Protection System Maintenance Program for the Protection System, Automatic Reclosing, and Sudden Pressure Relaying Components included in its performance-based program in accordance with Requirement R4. The evidence may include, but is not limited to, dated maintenance records, dated maintenance summaries, dated check-off lists, dated inspection records, or dated work orders.

R5. Each Transmission Owner, Generator Owner, and Distribution Provider shall demonstrate efforts to correct identified Unresolved Maintenance Issues. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

M5. Each Transmission Owner, Generator Owner, and Distribution Provider shall have evidence that it has undertaken efforts to correct identified Unresolved Maintenance

Issues in accordance with Requirement R5. The evidence may include, but is not limited to, work orders, replacement Component orders, invoices, project schedules with completed milestones, return material authorizations (RMAs) or purchase orders.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

As defined in the NERC Rules of Procedure, "Compliance Enforcement Authority" means NERC or the Regional Entity in their respective roles of monitoring and enforcing compliance with the NERC Reliability Standards.

1.2. Evidence Retention

The following evidence retention periods identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

The Transmission Owner, Generator Owner, and Distribution Provider shall each keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

For Requirement R1, the Transmission Owner, Generator Owner, and Distribution Provider shall each keep its current dated Protection System Maintenance Program, as well as any superseded versions since the preceding compliance audit, including the documentation that specifies the type of maintenance program applied for each Protection System, Automatic Reclosing, or Sudden Pressure Relaying Component Type.

For Requirement R2, Requirement R3, and Requirement R4, in cases where the interval of the maintenance activity is longer than the audit cycle, the Transmission Owner, Generator Owner, and Distribution Provider shall each keep documentation of the most recent performance of that maintenance activity for the Protection System, Automatic Reclosing, or Sudden Pressure Relaying Component. In cases where the interval of the maintenance activity is shorter than the audit cycle, documentation of all performances (in accordance with the tables) of that maintenance activity for the Protection System, Automatic Reclosing, or Sudden Pressure Relaying Component since the previous scheduled audit date shall be retained.

For Requirement R5 the Transmission Owner, Generator Owner, and Distribution Provider shall each keep documentation of Unresolved Maintenance Issues identified by the entity since the last audit, including all that were resolved since the last audit.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.3. Compliance Monitoring and Assessment Processes:

Compliance Audits

Self-Certifications

Spot Checking

Compliance Violation Investigations

Self-Reporting

Complaints

1.4. Additional Compliance Information

None

Table of Compliance Elements

Requirement Number	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	The entity's PSMP failed to specify whether one Component Type is being addressed by time-based or performance-based maintenance, or a combination of both (Part 1.1).	The entity's PSMP failed to specify whether two Component Types are being addressed by time-based or performance-based maintenance, or a combination of both (Part 1.1).	The entity's PSMP failed to specify whether three Component Types are being addressed by time-based or performance-based maintenance, or a combination of both. (Part 1.1). OR The entity's PSMP failed to include the applicable monitoring attributes applied to each Component Type consistent with the maintenance intervals specified in Tables 1-1 through 1-5, Table 2, Table 3, Tables 4-1 through 4-2, and Table 5 where monitoring is used to extend the maintenance intervals beyond those specified for unmonitored Components (Part 1.2).	The entity failed to establish a PSMP. OR The entity's PSMP failed to specify whether four or more Component Types are being addressed by time-based or performance-based maintenance, or a combination of both (Part 1.1). OR The entity's PSMP failed to include applicable station batteries in a time-based program (Part 1.1).
R2	The entity uses performance-based maintenance intervals in its PSMP but failed to reduce Countable Events to no more than 4% within three years.	NA	The entity uses performance-based maintenance intervals in its PSMP but failed to reduce Countable Events to no more than 4% within four years.	The entity uses performance-based maintenance intervals in its PSMP but: 1) Failed to establish the technical justification described within Requirement R2 for the initial use of the performance-based PSMP OR 2) Failed to reduce Countable Events to no more than 4% within five years OR

Requirement Number	Lower VSL	Moderate VSL	High VSL	Severe VSL
				3) Maintained a Segment with less than 60 Components OR 4) Failed to: • Annually update the list of Components, OR • Annually perform maintenance on the greater of 5% of the Segment population or 3 Components, OR • Annually analyze the program activities and results for each Segment.
R3	For Components included within a time-based maintenance program, the entity failed to maintain 5% or less of the total Components included within a specific Component Type in accordance with the minimum maintenance activities and maximum maintenance intervals prescribed within Tables 1-1 through 1-5, Table 2, Table 3, Tables 4-1 through 4-2, and Table 5.	For Components included within a time-based maintenance program, the entity failed to maintain more than 5% but 10% or less of the total Components included within a specific Component Type in accordance with the minimum maintenance activities and maximum maintenance intervals prescribed within Tables 1-1 through 1-5, Table 2, Table 3, Tables 4-1 through 4-2, and Table 5.	For Components included within a time-based maintenance program, the entity failed to maintain more than 10% but 15% or less of the total Components included within a specific Component Type in accordance with the minimum maintenance activities and maximum maintenance intervals prescribed within Tables 1-1 through 1-5, Table 2, Table 3, Tables 4-1 through 4-2, and Table 5.	For Components included within a time-based maintenance program, the entity failed to maintain more than 15% of the total Components included within a specific Component Type in accordance with the minimum maintenance activities and maximum maintenance intervals prescribed within Tables 1-1 through 1-5, Table 2, Table 3, Tables 4-1 through 4-2, and Table 5.

Requirement Number	Lower VSL	Moderate VSL	High VSL	Severe VSL
R4	For Components included within a performance-based maintenance program, the entity failed to maintain 5% or less of the annual scheduled maintenance for a specific Component Type in accordance with their performance-based PSMP.	For Components included within a performance-based maintenance program, the entity failed to maintain more than 5% but 10% or less of the annual scheduled maintenance for a specific Component Type in accordance with their performance-based PSMP.	For Components included within a performance-based maintenance program, the entity failed to maintain more than 10% but 15% or less of the annual scheduled maintenance for a specific Component Type in accordance with their performance-based PSMP.	For Components included within a performance-based maintenance program, the entity failed to maintain more than 15% of the annual scheduled maintenance for a specific Component Type in accordance with their performance-based PSMP.
R5	The entity failed to undertake efforts to correct 5 or fewer identified Unresolved Maintenance Issues.	The entity failed to undertake efforts to correct greater than 5 but less than or equal to 10 identified Unresolved Maintenance Issues.	The entity failed to undertake efforts to correct greater than 10 but less than or equal to 15 identified Unresolved Maintenance Issues.	The entity failed to undertake efforts to correct greater than 15 identified Unresolved Maintenance Issues.

D. Regional Variances

None.

E. Interpretations

None.

F. Supplemental Reference Documents

The following documents present a detailed discussion about determination of maintenance intervals and other useful information regarding establishment of a maintenance program.

1. *Supplementary Reference and FAQ - PRC-005-4 Protection System Maintenance,* Protection System Maintenance and Testing Standard Drafting Team (April 2014)
2. *Considerations for Maintenance and Testing of Auto-reclosing Schemes*, NERC System Analysis and Modeling Subcommittee, and NERC System Protection and Control Subcommittee (November 2012)
3. *Sudden Pressure Relays and Other Devices that Respond to Non-Electrical Quantities – SPCS Input for Standard Development in Response to FERC Order No. 758,* NERC System Protection and Control Subcommittee (December 2013)

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
1	December 1, 2005	1. Changed incorrect use of certain hyphens (-) to “en dash” (–) and “em dash (—).” 2. Added “periods” to items where appropriate. 3. Changed “Timeframe” to “Time Frame” in item D, 1.2.	01/20/05
1a	February 17, 2011	Added Appendix 1 - Interpretation regarding applicability of standard to protection of radially connected transformers	Project 2009-17 interpretation
1a	February 17, 2011	Adopted by Board of Trustees	

1a	September 26, 2011	FERC Order issued approving interpretation of R1 and R2 (FERC's Order is effective as of September 26, 2011)	
1.1a	February 1, 2012	Errata change: Clarified inclusion of generator interconnection Facility in Generator Owner's responsibility	Revision under Project 2010-07
1b	February 3, 2012	FERC Order issued approving interpretation of R1, R1.1, and R1.2 (FERC's Order dated March 14, 2012). Updated version from 1a to 1b.	Project 2009-10 Interpretation
1.1b	April 23, 2012	Updated standard version to 1.1b to reflect FERC approval of PRC-005-1b.	Revision under Project 2010-07

1.1b	May 9, 2012	PRC-005-1.1b was adopted by the Board of Trustees as part of Project 2010-07 (Generator Requirements at the Transmission Interface).	
2	November 7, 2012	Adopted by Board of Trustees	Project 2007-17 - Complete revision, absorbing maintenance requirements from PRC-005-1.1b, PRC-008-0, PRC-011-0, PRC-017-0
2	October 17, 2013	Errata Change: The Standards Committee approved an errata change to the implementation plan for PRC-005-2 to add the phrase "or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities;" to the second sentence under the "Retirement of Existing	
3	November 7, 2013	Adopted by the NERC Board of Trustees	Revised to address the FERC directive in Order No.758 to include Automatic Reclosing in maintenance programs.
3.1	February 12, 2014	Approved by the Standards Committee	Errata changes to correct capitalization of defined terms
X			Project 2007-17.3 – Revised to address the FERC directive in Order No. 758 to include sudden pressure relays in maintenance programs.

Table 1-1 Component Type - Protective Relay Excluding distributed UFLS and distributed UVLS (see Table 3)		
Component Attributes	**Maximum Maintenance Interval[3]**	**Maintenance Activities**
Any unmonitored protective relay not having all the monitoring attributes of a category below.	6 Calendar Years	For all unmonitored relays: • Verify that settings are as specified For non-microprocessor relays: • Test and, if necessary calibrate For microprocessor relays: • Verify operation of the relay inputs and outputs that are essential to proper functioning of the Protection System. • Verify acceptable measurement of power system input values.
Monitored microprocessor protective relay with the following: • Internal self-diagnosis and alarming (see Table 2). • Voltage and/or current waveform sampling three or more times per power cycle, and conversion of samples to numeric values for measurement calculations by microprocessor electronics. • Alarming for power supply failure (see Table 2).	12 Calendar Years	Verify: • Settings are as specified. • Operation of the relay inputs and outputs that are essential to proper functioning of the Protection System. • Acceptable measurement of power system input values.

[3] For the tables in this standard, a calendar year starts on the first day of a new year (January 1) after a maintenance activity has been completed.
For the tables in this standard, a calendar month starts on the first day of the first month after a maintenance activity has been completed.

Monitored microprocessor protective relay with preceding row attributes and the following: • Ac measurements are continuously verified by comparison to an independent ac measurement source, with alarming for excessive error (See Table 2). • Some or all binary or status inputs and control outputs are monitored by a process that continuously demonstrates ability to perform as designed, with alarming for failure (See Table 2). • Alarming for change of settings (See Table 2).	12 Calendar Years	Verify only the unmonitored relay inputs and outputs that are essential to proper functioning of the Protection System.

Table 1-2

Component Type - Communications Systems

Excluding distributed UFLS and distributed UVLS (see Table 3)

Component Attributes	Maximum Maintenance Interval	Maintenance Activities
Any unmonitored communications system necessary for correct operation of protective functions, and not having all the monitoring attributes of a category below.	4 Calendar Months	Verify that the communications system is functional.
	6 Calendar Years	Verify that the communications system meets performance criteria pertinent to the communications technology applied (e.g. signal level, reflected power, or data error rate). Verify operation of communications system inputs and outputs that are essential to proper functioning of the Protection System.
Any communications system with continuous monitoring or periodic automated testing for the presence of the channel function, and alarming for loss of function (See Table 2).	12 Calendar Years	Verify that the communications system meets performance criteria pertinent to the communications technology applied (e.g. signal level, reflected power, or data error rate). Verify operation of communications system inputs and outputs that are essential to proper functioning of the Protection System.
Any communications system with all of the following: • Continuous monitoring or periodic automated testing for the performance of the channel using criteria pertinent to the communications technology applied (e.g. signal level, reflected power, or data error rate, and alarming for excessive performance degradation). (See Table 2) • Some or all binary or status inputs and control outputs are monitored by a process that continuously demonstrates ability to perform as designed, with alarming for failure (See Table 2).	12 Calendar Years	Verify only the unmonitored communications system inputs and outputs that are essential to proper functioning of the Protection System

Table 1-3 Component Type - Voltage and Current Sensing Devices Providing Inputs to Protective Relays Excluding distributed UFLS and distributed UVLS (see Table 3)		
Component Attributes	**Maximum Maintenance Interval**	**Maintenance Activities**
Any voltage and current sensing devices not having monitoring attributes of the category below.	12 Calendar Years	Verify that current and voltage signal values are provided to the protective relays.
Voltage and Current Sensing devices connected to microprocessor relays with AC measurements are continuously verified by comparison of sensing input value, as measured by the microprocessor relay, to an independent ac measurement source, with alarming for unacceptable error or failure (see Table 2).	No periodic maintenance specified	None.

Table 1-4(a) Component Type – Protection System Station dc Supply Using Vented Lead-Acid (VLA) Batteries Excluding distributed UFLS and distributed UVLS (see Table 3) Protection System Station dc supply used only for non-BES interrupting devices for RAS, non-distributed UFLS systems, or non-distributed UVLS systems is excluded (see Table 1-4(e)).		
Component Attributes	**Maximum Maintenance Interval**	**Maintenance Activities**
Protection System Station dc supply using Vented Lead-Acid (VLA) batteries not having monitoring attributes of Table 1-4(f).	4 Calendar Months	Verify: • Station dc supply voltage Inspect: • Electrolyte level • For unintentional grounds
	18 Calendar Months	Verify: • Float voltage of battery charger • Battery continuity • Battery terminal connection resistance • Battery intercell or unit-to-unit connection resistance Inspect: • Cell condition of all individual battery cells where cells are visible – or measure battery cell/unit internal ohmic values where the cells are not visible • Physical condition of battery rack

Table 1-4(a) Component Type – Protection System Station dc Supply Using Vented Lead-Acid (VLA) Batteries Excluding distributed UFLS and distributed UVLS (see Table 3) Protection System Station dc supply used only for non-BES interrupting devices for RAS, non-distributed UFLS systems, or non-distributed UVLS systems is excluded (see Table 1-4(e)).		
Component Attributes	**Maximum Maintenance Interval**	**Maintenance Activities**
	18 Calendar Months -or- 6 Calendar Years	Verify that the station battery can perform as manufactured by evaluating cell/unit measurements indicative of battery performance (e.g. internal ohmic values or float current) against the station battery baseline. -or- Verify that the station battery can perform as manufactured by conducting a performance or modified performance capacity test of the entire battery bank.

Table 1-4(b)

Component Type – Protection System Station dc Supply Using Valve-Regulated Lead-Acid (VRLA) Batteries
Excluding distributed UFLS and distributed UVLS (see Table 3)

Protection System Station dc supply used only for non-BES interrupting devices for RAS, non-distributed UFLS systems, or non-distributed UVLS systems is excluded (see Table 1-4(e)).

Component Attributes	Maximum Maintenance Interval	Maintenance Activities
Protection System Station dc supply with Valve Regulated Lead-Acid (VRLA) batteries not having monitoring attributes of Table 1-4(f).	4 Calendar Months	Verify: • Station dc supply voltage Inspect: • For unintentional grounds
	6 Calendar Months	Inspect: • Condition of all individual units by measuring battery cell/unit internal ohmic values.
	18 Calendar Months	Verify: • Float voltage of battery charger • Battery continuity • Battery terminal connection resistance • Battery intercell or unit-to-unit connection resistance Inspect: • Physical condition of battery rack

Table 1-4(b) Component Type – Protection System Station dc Supply Using Valve-Regulated Lead-Acid (VRLA) Batteries Excluding distributed UFLS and distributed UVLS (see Table 3) Protection System Station dc supply used only for non-BES interrupting devices for RAS, non-distributed UFLS systems, or non-distributed UVLS systems is excluded (see Table 1-4(e)).		
Component Attributes	**Maximum Maintenance Interval**	**Maintenance Activities**
	6 Calendar Months -or- 3 Calendar Years	Verify that the station battery can perform as manufactured by evaluating cell/unit measurements indicative of battery performance (e.g. internal ohmic values or float current) against the station battery baseline. -or- Verify that the station battery can perform as manufactured by conducting a performance or modified performance capacity test of the entire battery bank.

Table 1-4(c) Component Type – Protection System Station dc Supply Using Nickel-Cadmium (NiCad) Batteries Excluding distributed UFLS and distributed UVLS (see Table 3) Protection System Station dc supply used only for non-BES interrupting devices for RAS, non-distributed UFLS system, or non-distributed UVLS systems is excluded (see Table 1-4(e)).		
Component Attributes	**Maximum Maintenance Interval**	**Maintenance Activities**
Protection System Station dc supply **Nickel-Cadmium (NiCad) batteries** not having monitoring attributes of Table 1-4(f).	4 Calendar Months	Verify: • Station dc supply voltage Inspect: • Electrolyte level • For unintentional grounds
	18 Calendar Months	Verify: • Float voltage of battery charger • Battery continuity • Battery terminal connection resistance • Battery intercell or unit-to-unit connection resistance Inspect: • Cell condition of all individual battery cells. • Physical condition of battery rack

Table 1-4(c) Component Type – Protection System Station dc Supply Using Nickel-Cadmium (NiCad) Batteries Excluding distributed UFLS and distributed UVLS (see Table 3) Protection System Station dc supply used only for non-BES interrupting devices for RAS, non-distributed UFLS system, or non-distributed UVLS systems is excluded (see Table 1-4(e)).		
Component Attributes	**Maximum Maintenance Interval**	**Maintenance Activities**
	6 Calendar Years	Verify that the station battery can perform as manufactured by conducting a performance or modified performance capacity test of the entire battery bank.

Table 1-4(d)

Component Type – Protection System Station dc Supply Using Non Battery Based Energy Storage

Excluding distributed UFLS and distributed UVLS (see Table 3)

Protection System Station dc supply used only for non-BES interrupting devices for RAS, non-distributed UFLS system, or non-distributed UVLS systems is excluded (see Table 1-4(e)).

Component Attributes	Maximum Maintenance Interval	Maintenance Activities
Any Protection System station dc supply not using a battery and not having monitoring attributes of Table 1-4(f).	4 Calendar Months	Verify: • Station dc supply voltage Inspect: • For unintentional grounds
	18 Calendar Months	Inspect: Condition of non-battery based dc supply
	6 Calendar Years	Verify that the dc supply can perform as manufactured when ac power is not present.

Table 1-4(e) Component Type – Protection System Station dc Supply for non-BES Interrupting Devices for RAS, non-distributed UFLS, and non-distributed UVLS systems		
Component Attributes	**Maximum Maintenance Interval**	**Maintenance Activities**
Any Protection System dc supply used for tripping only non-BES interrupting devices as part of a RAS, non-distributed UFLS, or non-distributed UVLS system and not having monitoring attributes of Table 1-4(f).	When control circuits are verified (See Table 1-5)	Verify Station dc supply voltage.

Table 1-4(f)
Exclusions for Protection System Station dc Supply Monitoring Devices and Systems

Component Attributes	Maximum Maintenance Interval	Maintenance Activities
Any station dc supply with high and low voltage monitoring and alarming of the battery charger voltage to detect charger overvoltage and charger failure (See Table 2).	No periodic maintenance specified	No periodic verification of station dc supply voltage is required.
Any battery based station dc supply with electrolyte level monitoring and alarming in every cell (See Table 2).		No periodic inspection of the electrolyte level for each cell is required.
Any station dc supply with unintentional dc ground monitoring and alarming (See Table 2).		No periodic inspection of unintentional dc grounds is required.
Any station dc supply with charger float voltage monitoring and alarming to ensure correct float voltage is being applied on the station dc supply (See Table 2).		No periodic verification of float voltage of battery charger is required.
Any battery based station dc supply with monitoring and alarming of battery string continuity (See Table 2).		No periodic verification of the battery continuity is required.
Any battery based station dc supply with monitoring and alarming of the intercell and/or terminal connection detail resistance of the entire battery (See Table 2).		No periodic verification of the intercell and terminal connection resistance is required.
Any Valve Regulated Lead-Acid (VRLA) or Vented Lead-Acid (VLA) station battery with internal ohmic value or float current monitoring and alarming, and evaluating present values relative to baseline internal ohmic values for every cell/unit (See Table 2).		No periodic evaluation relative to baseline of battery cell/unit measurements indicative of battery performance is required to verify the station battery can perform as manufactured.
Any Valve Regulated Lead-Acid (VRLA) or Vented Lead-Acid (VLA) station battery with monitoring and alarming of each cell/unit internal ohmic value (See Table 2).		No periodic inspection of the condition of all individual units by measuring battery cell/unit internal ohmic values of a station VRLA or Vented Lead-Acid (VLA) battery is required.

Table 1-5 Component Type - Control Circuitry Associated With Protective Functions Excluding distributed UFLS and distributed UVLS (see Table 3), Automatic Reclosing (see Table 4), and Sudden Pressure Relaying (see Table 5) Note: Table requirements apply to all Control Circuitry Components of Protection Systems, and RAS except as noted.		
Component Attributes	**Maximum Maintenance Interval**	**Maintenance Activities**
Trip coils or actuators of circuit breakers, interrupting devices, or mitigating devices (regardless of any monitoring of the control circuitry).	6 Calendar Years	Verify that each trip coil is able to operate the circuit breaker, interrupting device, or mitigating device.
Electromechanical lockout devices which are directly in a trip path from the protective relay to the interrupting device trip coil (regardless of any monitoring of the control circuitry).	6 Calendar Years	Verify electrical operation of electromechanical lockout devices.
Unmonitored control circuitry associated with RAS. (See Table 4-2(b) for RAS which include Automatic Reclosing.)	12 Calendar Years	Verify all paths of the control circuits essential for proper operation of the RAS.
Unmonitored control circuitry associated with protective functions inclusive of all auxiliary relays.	12 Calendar Years	Verify all paths of the trip circuits inclusive of all auxiliary relays through the trip coil(s) of the circuit breakers or other interrupting devices.
Control circuitry associated with protective functions and/or RAS whose integrity is monitored and alarmed (See Table 2).	No periodic maintenance specified	None.

Table 2 – Alarming Paths and Monitoring In Tables 1-1 through 1-5, Table 3, Tables 4-1 through 4-2, and Table 5 alarm attributes used to justify extended maximum maintenance intervals and/or reduced maintenance activities are subject to the following maintenance requirements		
Component Attributes	**Maximum Maintenance Interval**	**Maintenance Activities**
Any alarm path through which alarms in Tables 1-1 through 1-5, Table 3, Tables 4-1 through 4-2, and Table 5 are conveyed from the alarm origin to the location where corrective action can be initiated, and not having all the attributes of the "Alarm Path with monitoring" category below. Alarms are reported within 24 hours of detection to a location where corrective action can be initiated.	12 Calendar Years	Verify that the alarm path conveys alarm signals to a location where corrective action can be initiated.
Alarm Path with monitoring: The location where corrective action is taken receives an alarm within 24 hours for failure of any portion of the alarming path from the alarm origin to the location where corrective action can be initiated.	No periodic maintenance specified	None.

Table 3

Maintenance Activities and Intervals for distributed UFLS and distributed UVLS Systems

Component Attributes	Maximum Maintenance Interval	Maintenance Activities
Any unmonitored protective relay not having all the monitoring attributes of a category below.	6 Calendar Years	Verify that settings are as specified. For non-microprocessor relays: • Test and, if necessary calibrate. For microprocessor relays: • Verify operation of the relay inputs and outputs that are essential to proper functioning of the Protection System. • Verify acceptable measurement of power system input values.
Monitored microprocessor protective relay with the following: • Internal self-diagnosis and alarming (See Table 2). • Voltage and/or current waveform sampling three or more times per power cycle, and conversion of samples to numeric values for measurement calculations by microprocessor electronics. Alarming for power supply failure (See Table 2).	12 Calendar Years	Verify: • Settings are as specified. • Operation of the relay inputs and outputs that are essential to proper functioning of the Protection System. • Acceptable measurement of power system input values
Monitored microprocessor protective relay with preceding row attributes and the following: • Ac measurements are continuously verified by comparison to an independent ac measurement source, with alarming for excessive error (See Table 2).	12 Calendar Years	Verify only the unmonitored relay inputs and outputs that are essential to proper functioning of the Protection System.

Table 3 Maintenance Activities and Intervals for distributed UFLS and distributed UVLS Systems		
Component Attributes	**Maximum Maintenance Interval**	**Maintenance Activities**
• Some or all binary or status inputs and control outputs are monitored by a process that continuously demonstrates ability to perform as designed, with alarming for failure (See Table 2). Alarming for change of settings (See Table 2).		
Voltage and/or current sensing devices associated with UFLS or UVLS systems.	12 Calendar Years	Verify that current and/or voltage signal values are provided to the protective relays.
Protection System dc supply for tripping non-BES interrupting devices used only for a UFLS or UVLS system.	12 Calendar Years	Verify Protection System dc supply voltage.
Control circuitry between the UFLS or UVLS relays and electromechanical lockout and/or tripping auxiliary devices (excludes non-BES interrupting device trip coils).	12 Calendar Years	Verify the path from the relay to the lockout and/or tripping auxiliary relay (including essential supervisory logic).
Electromechanical lockout and/or tripping auxiliary devices associated only with UFLS or UVLS systems (excludes non-BES interrupting device trip coils).	12 Calendar Years	Verify electrical operation of electromechanical lockout and/or tripping auxiliary devices.
Control circuitry between the electromechanical lockout and/or tripping auxiliary devices and the non-BES interrupting devices in UFLS or UVLS systems, or between UFLS or UVLS relays (with no interposing electromechanical lockout or auxiliary device) and the non-BES interrupting devices (excludes non-BES interrupting device trip coils).	No periodic maintenance specified	None.
Trip coils of non-BES interrupting devices in UFLS or UVLS systems.	No periodic maintenance specified	None.

Table 4-1

Maintenance Activities and Intervals for Automatic Reclosing Components

Component Type – Reclosing Relay

Component Attributes	Maximum Maintenance Interval	Maintenance Activities
Any unmonitored reclosing relay not having all the monitoring attributes of a category below.	6 Calendar Years	Verify that settings are as specified. For non-microprocessor relays: • Test and, if necessary calibrate For microprocessor relays: • Verify operation of the relay inputs and outputs that are essential to proper functioning of the Automatic Reclosing.
Monitored microprocessor reclosing relay with the following: • Internal self-diagnosis and alarming (See Table 2). • Alarming for power supply failure (See Table 2).	12 Calendar Years	Verify: • Settings are as specified. • Operation of the relay inputs and outputs that are essential to proper functioning of the Automatic Reclosing.

Table 4-2(a) Maintenance Activities and Intervals for Automatic Reclosing Components Component Type – Control Circuitry Associated with Reclosing Relays that are NOT an Integral Part of an RAS		
Component Attributes	**Maximum Maintenance Interval**	**Maintenance Activities**
Unmonitored Control circuitry associated with Automatic Reclosing that is not an integral part of an RAS.	12 Calendar Years	Verify that Automatic Reclosing, upon initiation, does not issue a premature closing command to the close circuitry.
Control circuitry associated with Automatic Reclosing that is not part of an RAS and is monitored and alarmed for conditions that would result in a premature closing command. (See Table 2)	No periodic maintenance specified	None.

Table 4-2(b) Maintenance Activities and Intervals for Automatic Reclosing Components Component Type – Control Circuitry Associated with Reclosing Relays that ARE an Integral Part of an RAS		
Component Attributes	**Maximum Maintenance Interval**	**Maintenance Activities**
Close coils or actuators of circuit breakers or similar devices that are used in conjunction with Automatic Reclosing as part of an RAS (regardless of any monitoring of the control circuitry).	6 Calendar Years	Verify that each close coil or actuator is able to operate the circuit breaker or mitigating device.
Unmonitored close control circuitry associated with Automatic Reclosing used as an integral part of an RAS.	12 Calendar Years	Verify all paths of the control circuits associated with Automatic Reclosing that are essential for proper operation of the RAS.
Control circuitry associated with Automatic Reclosing that is an integral part of an RAS whose integrity is monitored and alarmed. (See Table 2)	No periodic maintenance specified	None.

Table 5

Maintenance Activities and Intervals for Sudden Pressure Relaying

Note: In cases where Components of Sudden Pressure Relaying are common to Components listed in Table 1-5, the Components only need to be tested once during a distinct maintenance interval.

Component Attributes	Maximum Maintenance Interval	Maintenance Activities
Any fault pressure relay.	6 Calendar Years	Verify the pressure or flow sensing mechanism is operable.
Electromechanical lockout devices which are directly in a trip path from the fault pressure relay to the interrupting device trip coil (regardless of any monitoring of the control circuitry).	6 Calendar Years	Verify electrical operation of electromechanical lockout devices.
Unmonitored control circuitry associated with Sudden Pressure Relaying.	12 Calendar Years	Verify all paths of the trip circuits inclusive of all auxiliary relays through the trip coil(s) of the circuit breakers or other interrupting devices.
Control circuitry associated with Sudden Pressure Relaying whose integrity is monitored and alarmed (See Table 2).	No periodic maintenance specified	None.

PRC-005 — Attachment A

Criteria for a Performance-Based Protection System Maintenance Program

Purpose: To establish a technical basis for initial and continued use of a performance-based Protection System Maintenance Program (PSMP).

To establish the technical justification for the initial use of a performance-based PSMP:

1. Develop a list with a description of Components included in each designated Segment, with a minimum Segment population of 60 Components.
2. Maintain the Components in each Segment according to the time-based maximum allowable intervals established in Tables 1-1 through 1-5, Table 3, Tables 4-1 through 4-2, and Table 5 until results of maintenance activities for the Segment are available for a minimum of 30 individual Components of the Segment.
3. Document the maintenance program activities and results for each Segment, including maintenance dates and Countable Events for each included Component.
4. Analyze the maintenance program activities and results for each Segment to determine the overall performance of the Segment and develop maintenance intervals.
5. Determine the maximum allowable maintenance interval for each Segment such that the Segment experiences Countable Events on no more than 4% of the Components within the Segment, for the greater of either the last 30 Components maintained or all Components maintained in the previous year.

To maintain the technical justification for the ongoing use of a performance-based PSMP:

1. At least annually, update the list of Components and Segments and/or description if any changes occur within the Segment.
2. Perform maintenance on the greater of 5% of the Components (addressed in the performance based PSMP) in each Segment or 3 individual Components within the Segment in each year.
3. For the prior year, analyze the maintenance program activities and results for each Segment to determine the overall performance of the Segment.
4. Using the prior year's data, determine the maximum allowable maintenance interval for each Segment such that the Segment experiences Countable Events on no more than 4% of the Components within the Segment, for the greater of either the last 30 Components maintained or all Components maintained in the previous year.

If the Components in a Segment maintained through a performance-based PSMP experience 4% or more Countable Events, develop, document, and implement an action plan to reduce the Countable Events to less than 4% of the Segment population within 3 years.

Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Development Steps Completed

1. SAR posted for comment February 13, 2014 – March 14, 2014.
2. The draft standard was posted for a 45-day concurrent comment and ballot period of April 17, 2014–June 3, 2014.
3. The draft standard was posted for a 45-day additional comment and ballot period of July 30 – September 12, 2014

Description of Current Draft

The Protection System Maintenance and Testing Standard Drafting Team (PSMT SDT) is posting draft ~~2~~ 3 of PRC-005-4~~X~~ for a ~~45~~10-day ~~comment period and~~final -ballot~~ in the last ten days of the comment period under the new Standards Process Manual (Effective: June 26, 2013)~~.

This draft contains the technical content of the standard. A parallel effort in the Project 2014-01, Standards Applicability for Dispersed Generation Resources, will post an applicability change to PRC-005-2 and PRC-005-3 for comment and ballot.

Anticipated Actions	Anticipated Date
45-day Formal Comment Period with Parallel Ballot	April 17 – June 2, 2014
45-day Additional Formal Comment Period with Parallel Ballot (if necessary)	July 30~~,~~ – September 12, 2014
Final ballot	October 20, 2014
BOT adoption	November 13, 2014

Definitions of Terms Used in Standard

This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the Reliability Standards Glossary of Terms (Glossary) are not repeated here. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, this defined term will be removed from the individual standard and added to the Glossary.

Protection System Maintenance Program (PSMP) — An ongoing program by which Protection System, Automatic Reclosing, and Sudden Pressure Relaying Components are kept in working order and proper operation of malfunctioning components is restored. A maintenance program for a specific Component includes one or more of the following activities:

- Verify — Determine that the Component is functioning correctly.
- Monitor — Observe the routine in-service operation of the Component.
- Test — Apply signals to a Component to observe functional performance or output behavior, or to diagnose problems.
- Inspect — Examine for signs of Component failure, reduced performance or degradation.
- Calibrate — Adjust the operating threshold or measurement accuracy of a measuring element to meet the intended performance requirement.

See Section A.6, Definitions Used in this Standard, for additional definitions that are new or modified for use within this standard.

When this standard has received ballot approval, the text boxes will be moved to the Application Guidelines Section of the Standard.

A. Introduction

1. **Title: Protection System, Automatic Reclosing, and Sudden Pressure Relaying Maintenance**
2. **Number: PRC-005-4~~X~~**
3. **Purpose:** To document and implement programs for the maintenance of all Protection Systems, Automatic Reclosing, and Sudden Pressure Relaying affecting the reliability of the Bulk Electric System (BES) so that they are kept in working order.

Rationale for Applicability Section: This section does not reflect the applicability changes that will be proposed by the Project 2014-01 Standards Applicability for Dispersed Generation Resources standards drafting team. The changes in this posted version and those being made by the Project 2014-01 standards drafting team do not overlap.

Additionally, to align with ongoing NERC standards development in Project 2010-05.2: Special Protection Systems, the term “Special Protection Systems” in PRC-005-~~X~~ 4 was replaced by the term “Remedial Action Schemes.” These terms are synonymous in the NERC Glossary of Terms.

4. **Applicability:**

4.1. Functional Entities:

4.1.1 Transmission Owner

4.1.2 Generator Owner

4.1.3 Distribution Provider

4.2. Facilities:

4.2.1 Protection Systems and Sudden Pressure Relaying that are installed for the purpose of detecting Faults on BES Elements (lines, buses, transformers, etc.)

4.2.2 Protection Systems used for underfrequency load-shedding systems installed per ERO underfrequency load-shedding requirements.

4.2.3 Protection Systems used for undervoltage load-shedding systems installed to prevent system voltage collapse or voltage instability for BES reliability.

4.2.4 Protection Systems installed as a Remedial Action Scheme (RAS) for BES reliability.

4.2.5 Protection Systems and Sudden Pressure Relaying for generator Facilities that are part of the BES, including:

4.2.5.1 Protection Systems that act to trip the generator either directly or via lockout or auxiliary tripping relays.

4.2.5.2 Protection Systems and Sudden Pressure Relaying for generator step-up transformers for generators that are part of the BES.

4.2.5.3 Protection Systems and Sudden Pressure Relaying for transformers connecting aggregated generation, where the aggregated generation is part of the BES (e.g., transformers connecting facilities such as wind-farms to the BES).

4.2.5.4 Protection Systems and Sudden Pressure Relaying for station service or excitation transformers connected to the generator bus of generators which are part of the BES, that act to trip the generator either directly or via lockout or tripping auxiliary relays.

4.2.6 Automatic Reclosing[1], including:

[1] Automatic Reclosing addressed in Section 4.2.6.1 and 4.2.6.2 may be excluded if the equipment owner can demonstrate that a close-in three-phase fault present for twice the normal clearing time (capturing a minimum trip-close-trip time delay) does not result in a total loss of gross generation in the Interconnection exceeding the gross capacity of the largest relevant BES generating unit where the Automatic Reclosing is applied.

4.2.6.1 Automatic Reclosing applied on the terminals of Elements connected to the BES bus located at generating plant substations where the total installed gross generating plant capacity is greater than the gross capacity of the largest BES generating unit within the Balancing Authority Area or, if a member of a Reserve Sharing Group, the largest generating unit within the Reserve Sharing Group. [2]

4.2.6.2 Automatic Reclosing applied on the terminals of all BES Elements at substations one bus away from generating plants specified in Section 4.2.6.1 when the substation is less than 10 circuit-miles from the generating plant substation.

4.2.6.3. Automatic Reclosing applied as an integral part of an RAS specified in Section 4.2.4.

5. **Effective Date:** See Implementation Plan

6. **Definitions Used in this Standard:**

Automatic Reclosing – Includes the following Components:

- Reclosing relay
- Control circuitry associated with the reclosing relay.

Sudden Pressure Relaying – A system that trips an interrupting device(s) to isolate the equipment it is monitoring and includes the following Components:

- Fault pressure relay – a mechanical relay or device that detects rapid changes in gas pressure, oil pressure, or oil flow that are indicative of Faults within liquid-filled, wire-wound equipment
- Control circuitry associated with a fault pressure relay

Unresolved Maintenance Issue – A deficiency identified during a maintenance activity that causes the Component to not meet the intended performance, cannot be corrected during the maintenance interval, and requires follow-up corrective action.

Segment – Components of a consistent design standard, or a particular model or type from a single manufacturer that typically share other common elements. Consistent performance is expected across the entire population of a Segment. A Segment must contain at least sixty (60) individual Components.

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[2] The largest BES generating unit within the Balancing Authority Area or the largest generating unit within the Reserve Sharing Group, as applicable, is subject to change. As a result of such a change, the Automatic Reclosing Components subject to the standard could change effective on the date of such change.

Component Type –

- Any one of the five specific elements of a Protection System.
- Any one of the two specific elements of Automatic Reclosing.
- Any one of the two specific elements of Sudden Pressure Relaying.

Rationale for the deletion of part of the definition of Component: The SDT determined that it was explanatory in nature and adequately addressed in the Supplementary Reference and FAQ Document.

Component – Any individual discrete piece of equipment included in a Protection System, Automatic Reclosing, or Sudden Pressure Relaying.

Countable Event – A failure of a Component requiring repair or replacement, any condition discovered during the maintenance activities in Tables 1-1 through 1-5, Table 3, Tables 4-1 through 4-2, and Table 5, which requires corrective action or a Protection System Misoperation attributed to hardware failure or calibration failure. Misoperations due to product design errors, software errors, relay settings different from specified settings, Protection System Component, Automatic Reclosing, or Sudden Pressure Relaying configuration or application errors are not included in Countable Events.

B. Requirements and Measures

R1. Each Transmission Owner, Generator Owner, and Distribution Provider shall establish a Protection System Maintenance Program (PSMP) for its Protection Systems, Automatic Reclosing, and Sudden Pressure Relaying identified in Section 4.2, Facilities. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning*]

The PSMP shall:

1.1. Identify which maintenance method (time-based, performance-based per PRC-005 Attachment A, or a combination) is used to address each Protection System, Automatic Reclosing, and Sudden Pressure Relaying Component Type. All batteries associated with the station dc supply Component Type of a Protection System shall be included in a time-based program as described in Table 1-4 and Table 3.

1.2. Include the applicable monitored Component attributes applied to each Protection System, Automatic Reclosing, and Sudden Pressure Relaying Component Type consistent with the maintenance intervals specified in Tables 1-1 through 1-5, Table 2, Table 3, Table 4-1 through 4-2, and Table 5 where monitoring is used to extend the maintenance intervals beyond those specified for unmonitored Protection System, Automatic Reclosing, and Sudden Pressure Relaying Components.

M1. Each Transmission Owner, Generator Owner and Distribution Provider shall have a documented Protection System Maintenance Program in accordance with Requirement R1.

For each Protection System, Automatic Reclosing, and Sudden Pressure Relaying Component Type, the documentation shall include the type of maintenance method applied (time-based, performance-based, or a combination of these maintenance methods), and shall include all batteries associated with the station dc supply Component Types in a time-based program as described in Table 1-4 and Table 3. (Part 1.1)

For Component Types that use monitoring to extend the maintenance intervals, the responsible entity(s) shall have evidence for each Protection System, Automatic Reclosing, and Sudden Pressure Relaying Component Type (such as manufacturer's specifications or engineering drawings) of the appropriate monitored Component attributes as specified in Tables 1-1 through 1-5, Table 2, Table 3, Table 4-1 through 4-2, and Table 5. (Part 1.2)

R2. Each Transmission Owner, Generator Owner, and Distribution Provider that uses performance-based maintenance intervals in its PSMP shall follow the procedure established in PRC-005 Attachment A to establish and maintain its performance-based intervals. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

M2. Each Transmission Owner, Generator Owner, and Distribution Provider that uses performance-based maintenance intervals shall have evidence that its current performance-based maintenance program(s) is in accordance with Requirement R2, which may include, but is not limited to, Component lists, dated maintenance records, and dated analysis records and results.

Rationale for R3 Part 3.1: In the last posting, the SDT included language in the standard that was originally in the implementation plan that required completion of maintenance activities within three years for newly-identified Automatic Reclosing Components following a notification under Requirement R6, which has been removed. After further discussion, the SDT determined that a separate shorter timeframe for maintenance of newly-identified Automatic Reclosing Components created unnecessary complication within the standard. The SDT agreed that entities should be responsible for maintaining the Automatic Reclosing Components subject to the standard, whether existing, newly added or newly within scope based on a change in the largest generating unit in the BA or, if a member of a Reserve Sharing Group, the largest generating unit within the Reserve Sharing Group according to the timeframes in the maintenance tables. Therefore, 3.1 and its subparts have been removed and have not been reinserted into the implementation plan.

R3. Each Transmission Owner, Generator Owner, and Distribution Provider that utilizes time-based maintenance program(s) shall maintain its Protection System, Automatic Reclosing, and Sudden Pressure Relaying Components that are included within the time-based maintenance program in accordance with the minimum maintenance activities and maximum maintenance intervals prescribed within Tables 1-1 through

1-5, Table 2, Table 3, Table 4-1 through 4-2, and Table 5. *[Violation Risk Factor: High] [Time Horizon: Operations Planning]*

M3. Each Transmission Owner, Generator Owner, and Distribution Provider that utilizes time-based maintenance program(s) shall have evidence that it has maintained its Protection System, Automatic Reclosing, and Sudden Pressure Relaying Components included within its time-based program in accordance with Requirement R3. The evidence may include, but is not limited to, dated maintenance records, dated maintenance summaries, dated check-off lists, dated inspection records, or dated work orders.

Rationale for R4 Part 4.1: In the last posting, the SDT included language in the standard that was originally in the implementation plan that required completion of maintenance activities within three years for newly-identified Automatic Reclosing Components following a notification under Requirement R6, which has been removed. After further discussion, the SDT determined that a separate shorter timeframe for maintenance of newly-identified Automatic Reclosing Components created unnecessary complication within the standard. The SDT agreed that entities should be responsible for maintaining the Automatic Reclosing Components subject to the standard, whether existing, newly added or newly within scope based on a change in the largest generating unit in the BA or, if a member of a Reserve Sharing Group, the largest generating unit within the Reserve Sharing Group according to the timeframes in the maintenance tables. Therefore, 4.1 and its subparts have been removed and have not been reinserted into the implementation plan.

R4. Each Transmission Owner, Generator Owner, and Distribution Provider that utilizes performance-based maintenance program(s) in accordance with Requirement R2 shall implement and follow its PSMP for its Protection System, Automatic Reclosing, and Sudden Pressure Relaying Components that are included within the performance-based program(s). *[Violation Risk Factor: High] [Time Horizon: Operations Planning]*

M4. Each Transmission Owner, Generator Owner, and Distribution Provider that utilizes performance-based maintenance intervals in accordance with Requirement R2 shall have evidence that it has implemented the Protection System Maintenance Program for the Protection System, Automatic Reclosing, and Sudden Pressure Relaying Components included in its performance-based program in accordance with Requirement R4. The evidence may include, but is not limited to, dated maintenance records, dated maintenance summaries, dated check-off lists, dated inspection records, or dated work orders.

R5. Each Transmission Owner, Generator Owner, and Distribution Provider shall demonstrate efforts to correct identified Unresolved Maintenance Issues. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

M5. Each Transmission Owner, Generator Owner, and Distribution Provider shall have evidence that it has undertaken efforts to correct identified Unresolved Maintenance

Issues in accordance with Requirement R5. The evidence may include, but is not limited to, work orders, replacement Component orders, invoices, project schedules with completed milestones, return material authorizations (RMAs) or purchase orders.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

As defined in the NERC Rules of Procedure, "Compliance Enforcement Authority" means NERC or the Regional Entity in their respective roles of monitoring and enforcing compliance with the NERC Reliability Standards.

1.2. Evidence Retention

The following evidence retention periods identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

The Transmission Owner, Generator Owner, and Distribution Provider shall each keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

For Requirement R1, the Transmission Owner, Generator Owner, and Distribution Provider shall each keep its current dated Protection System Maintenance Program, as well as any superseded versions since the preceding compliance audit, including the documentation that specifies the type of maintenance program applied for each Protection System, Automatic Reclosing, or Sudden Pressure Relaying Component Type.

For Requirement R2, Requirement R3, and Requirement R4, ~~and Requirement R5,~~ in cases where the interval of the maintenance activity is longer than the audit cycle, the Transmission Owner, Generator Owner, and Distribution Provider shall each keep documentation of the most recent performance of that maintenance activity for the Protection System, Automatic Reclosing, or Sudden Pressure Relaying Component. In cases where the interval of the maintenance activity is shorter than the audit cycle, documentation of all performances (in accordance with the tables) of that maintenance activity for the Protection System, Automatic Reclosing, or Sudden Pressure Relaying Component since the previous scheduled audit date shall be retained.

For Requirement R5 the Transmission Owner, Generator Owner, and Distribution Provider shall each keep documentation of Unresolved Maintenance Issues identified by the entity since the last audit, including all that were resolved since the last audit.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.3. Compliance Monitoring and Assessment Processes:

Compliance Audits

Self-Certifications

Spot Checking

Compliance Violation Investigations

Self-Reporting

Complaints

1.4. Additional Compliance Information

None

Table of Compliance Elements

Requirement Number	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	The entity's PSMP failed to specify whether one Component Type is being addressed by time-based or performance-based maintenance, or a combination of both (Part 1.1).	The entity's PSMP failed to specify whether two Component Types are being addressed by time-based or performance-based maintenance, or a combination of both (Part 1.1).	The entity's PSMP failed to specify whether three Component Types are being addressed by time-based or performance-based maintenance, or a combination of both. (Part 1.1). OR The entity's PSMP failed to include the applicable monitoring attributes applied to each Component Type consistent with the maintenance intervals specified in Tables 1-1 through 1-5, Table 2, Table 3, Tables 4-1 through 4-2, and Table 5 where monitoring is used to extend the maintenance intervals beyond those specified for unmonitored Components (Part 1.2).	The entity failed to establish a PSMP. OR The entity's PSMP failed to specify whether four or more Component Types are being addressed by time-based or performance-based maintenance, or a combination of both (Part 1.1). OR The entity's PSMP failed to include applicable station batteries in a time-based program (Part 1.1).
R2	The entity uses performance-based maintenance intervals in its PSMP but failed to reduce Countable Events to no more than 4% within three years.	NA	The entity uses performance-based maintenance intervals in its PSMP but failed to reduce Countable Events to no more than 4% within four years.	The entity uses performance-based maintenance intervals in its PSMP but: 1) Failed to establish the technical justification described within Requirement R2 for the initial use of the performance-based PSMP OR 2) Failed to reduce Countable Events to no more than 4% within five years OR

Requirement Number	Lower VSL	Moderate VSL	High VSL	Severe VSL
				3) Maintained a Segment with less than 60 Components OR 4) Failed to: • Annually update the list of Components, OR • Annually perform maintenance on the greater of 5% of the Segment population or 3 Components, OR • Annually analyze the program activities and results for each Segment.
R3	For Components included within a time-based maintenance program, the entity failed to maintain 5% or less of the total Components included within a specific Component Type in accordance with the minimum maintenance activities and maximum maintenance intervals prescribed within Tables 1-1 through 1-5, Table 2, Table 3, Tables 4-1 through 4-2, and Table 5.	For Components included within a time-based maintenance program, the entity failed to maintain more than 5% but 10% or less of the total Components included within a specific Component Type in accordance with the minimum maintenance activities and maximum maintenance intervals prescribed within Tables 1-1 through 1-5, Table 2, Table 3, Tables 4-1 through 4-2, and Table 5.	For Components included within a time-based maintenance program, the entity failed to maintain more than 10% but 15% or less of the total Components included within a specific Component Type in accordance with the minimum maintenance activities and maximum maintenance intervals prescribed within Tables 1-1 through 1-5, Table 2, Table 3, Tables 4-1 through 4-2, and Table 5.	For Components included within a time-based maintenance program, the entity failed to maintain more than 15% of the total Components included within a specific Component Type in accordance with the minimum maintenance activities and maximum maintenance intervals prescribed within Tables 1-1 through 1-5, Table 2, Table 3, Tables 4-1 through 4-2, and Table 5.

Requirement Number	Lower VSL	Moderate VSL	High VSL	Severe VSL
R4	For Components included within a performance-based maintenance program, the entity failed to maintain 5% or less of the annual scheduled maintenance for a specific Component Type in accordance with their performance-based PSMP.	For Components included within a performance-based maintenance program, the entity failed to maintain more than 5% but 10% or less of the annual scheduled maintenance for a specific Component Type in accordance with their performance-based PSMP.	For Components included within a performance-based maintenance program, the entity failed to maintain more than 10% but 15% or less of the annual scheduled maintenance for a specific Component Type in accordance with their performance-based PSMP.	For Components included within a performance-based maintenance program, the entity failed to maintain more than 15% of the annual scheduled maintenance for a specific Component Type in accordance with their performance-based PSMP.
R5	The entity failed to undertake efforts to correct 5 or fewer identified Unresolved Maintenance Issues.	The entity failed to undertake efforts to correct greater than 5 but less than or equal to 10 identified Unresolved Maintenance Issues.	The entity failed to undertake efforts to correct greater than 10 but less than or equal to 15 identified Unresolved Maintenance Issues.	The entity failed to undertake efforts to correct greater than 15 identified Unresolved Maintenance Issues.

D. Regional Variances

None.

E. Interpretations

None.

F. Supplemental Reference Documents

The following documents present a detailed discussion about determination of maintenance intervals and other useful information regarding establishment of a maintenance program.

1. *Supplementary Reference and FAQ - PRC-005-~~X~~4 Protection System Maintenance,* Protection System Maintenance and Testing Standard Drafting Team (April 2014)
2. *Considerations for Maintenance and Testing of Auto-reclosing Schemes*, NERC System Analysis and Modeling Subcommittee, and NERC System Protection and Control Subcommittee (November 2012)
3. *Sudden Pressure Relays and Other Devices that Respond to Non-Electrical Quantities – SPCS Input for Standard Development in Response to FERC Order No. 758,* NERC System Protection and Control Subcommittee (December 2013)

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
1	December 1, 2005	1. Changed incorrect use of certain hyphens (-) to “en dash” (–) and “em dash (—).” 2. Added “periods” to items where appropriate. 3. Changed “Timeframe” to “Time Frame” in item D, 1.2.	01/20/05
1a	February 17, 2011	Added Appendix 1 - Interpretation regarding applicability of standard to protection of radially connected transformers	Project 2009-17 interpretation
1a	February 17, 2011	Adopted by Board of Trustees	

1a	September 26, 2011	FERC Order issued approving interpretation of R1 and R2 (FERC's Order is effective as of September 26, 2011)	
1.1a	February 1, 2012	Errata change: Clarified inclusion of generator interconnection Facility in Generator Owner's responsibility	Revision under Project 2010-07
1b	February 3, 2012	FERC Order issued approving interpretation of R1, R1.1, and R1.2 (FERC's Order dated March 14, 2012). Updated version from 1a to 1b.	Project 2009-10 Interpretation
1.1b	April 23, 2012	Updated standard version to 1.1b to reflect FERC approval of PRC-005-1b.	Revision under Project 2010-07

1.1b	May 9, 2012	PRC-005-1.1b was adopted by the Board of Trustees as part of Project 2010-07 (Generator Requirements at the Transmission Interface).	
2	November 7, 2012	Adopted by Board of Trustees	Project 2007-17 - Complete revision, absorbing maintenance requirements from PRC-005-1.1b, PRC-008-0, PRC-011-0, PRC-017-0
2	October 17, 2013	Errata Change: The Standards Committee approved an errata change to the implementation plan for PRC-005-2 to add the phrase "or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities;" to the second sentence under the "Retirement of Existing	
3	November 7, 2013	Adopted by the NERC Board of Trustees	Revised to address the FERC directive in Order No.758 to include Automatic Reclosing in maintenance programs.
3.1	February 12, 2014	Approved by the Standards Committee	Errata changes to correct capitalization of defined terms
X			Project 2007-17.3 – Revised to address the FERC directive in Order No. 758 to include sudden pressure relays in maintenance programs.

Table 1-1 Component Type - Protective Relay Excluding distributed UFLS and distributed UVLS (see Table 3)		
Component Attributes	**Maximum Maintenance Interval[3]**	**Maintenance Activities**
Any unmonitored protective relay not having all the monitoring attributes of a category below.	6 Calendar Years	For all unmonitored relays: • Verify that settings are as specified For non-microprocessor relays: • Test and, if necessary calibrate For microprocessor relays: • Verify operation of the relay inputs and outputs that are essential to proper functioning of the Protection System. • Verify acceptable measurement of power system input values.
Monitored microprocessor protective relay with the following: • Internal self-diagnosis and alarming (see Table 2). • Voltage and/or current waveform sampling three or more times per power cycle, and conversion of samples to numeric values for measurement calculations by microprocessor electronics. • Alarming for power supply failure (see Table 2).	12 Calendar Years	Verify: • Settings are as specified. • Operation of the relay inputs and outputs that are essential to proper functioning of the Protection System. • Acceptable measurement of power system input values.

[3] For the tables in this standard, a calendar year starts on the first day of a new year (January 1) after a maintenance activity has been completed.
For the tables in this standard, a calendar month starts on the first day of the first month after a maintenance activity has been completed.

Monitored microprocessor protective relay with preceding row attributes and the following: • Ac measurements are continuously verified by comparison to an independent ac measurement source, with alarming for excessive error (See Table 2). • Some or all binary or status inputs and control outputs are monitored by a process that continuously demonstrates ability to perform as designed, with alarming for failure (See Table 2). • Alarming for change of settings (See Table 2).	12 Calendar Years	Verify only the unmonitored relay inputs and outputs that are essential to proper functioning of the Protection System.

Table 1-2 Component Type - Communications Systems Excluding distributed UFLS and distributed UVLS (see Table 3)		
Component Attributes	**Maximum Maintenance Interval**	**Maintenance Activities**
Any unmonitored communications system necessary for correct operation of protective functions, and not having all the monitoring attributes of a category below.	4 Calendar Months	Verify that the communications system is functional.
	6 Calendar Years	Verify that the communications system meets performance criteria pertinent to the communications technology applied (e.g. signal level, reflected power, or data error rate). Verify operation of communications system inputs and outputs that are essential to proper functioning of the Protection System.
Any communications system with continuous monitoring or periodic automated testing for the presence of the channel function, and alarming for loss of function (See Table 2).	12 Calendar Years	Verify that the communications system meets performance criteria pertinent to the communications technology applied (e.g. signal level, reflected power, or data error rate). Verify operation of communications system inputs and outputs that are essential to proper functioning of the Protection System.
Any communications system with all of the following: • Continuous monitoring or periodic automated testing for the performance of the channel using criteria pertinent to the communications technology applied (e.g. signal level, reflected power, or data error rate, and alarming for excessive performance degradation). (See Table 2) • Some or all binary or status inputs and control outputs are monitored by a process that continuously demonstrates ability to perform as designed, with alarming for failure (See Table 2).	12 Calendar Years	Verify only the unmonitored communications system inputs and outputs that are essential to proper functioning of the Protection System

Table 1-3 Component Type - Voltage and Current Sensing Devices Providing Inputs to Protective Relays Excluding distributed UFLS and distributed UVLS (see Table 3)		
Component Attributes	**Maximum Maintenance Interval**	**Maintenance Activities**
Any voltage and current sensing devices not having monitoring attributes of the category below.	12 Calendar Years	Verify that current and voltage signal values are provided to the protective relays.
Voltage and Current Sensing devices connected to microprocessor relays with AC measurements are continuously verified by comparison of sensing input value, as measured by the microprocessor relay, to an independent ac measurement source, with alarming for unacceptable error or failure (see Table 2).	No periodic maintenance specified	None.

Table 1-4(a)

Component Type – Protection System Station dc Supply Using Vented Lead-Acid (VLA) Batteries
Excluding distributed UFLS and distributed UVLS (see Table 3)

Protection System Station dc supply used only for non-BES interrupting devices for RAS, non-distributed UFLS systems, or non-distributed UVLS systems is excluded (see Table 1-4(e)).

Component Attributes	Maximum Maintenance Interval	Maintenance Activities
Protection System Station dc supply using Vented Lead-Acid (VLA) batteries not having monitoring attributes of Table 1-4(f).	4 Calendar Months	Verify: • Station dc supply voltage Inspect: • Electrolyte level • For unintentional grounds
	18 Calendar Months	Verify: • Float voltage of battery charger • Battery continuity • Battery terminal connection resistance • Battery intercell or unit-to-unit connection resistance Inspect: • Cell condition of all individual battery cells where cells are visible – or measure battery cell/unit internal ohmic values where the cells are not visible • Physical condition of battery rack

Table 1-4(a) Component Type – Protection System Station dc Supply Using Vented Lead-Acid (VLA) Batteries Excluding distributed UFLS and distributed UVLS (see Table 3) Protection System Station dc supply used only for non-BES interrupting devices for RAS, non-distributed UFLS systems, or non-distributed UVLS systems is excluded (see Table 1-4(e)).		
Component Attributes	**Maximum Maintenance Interval**	**Maintenance Activities**
	18 Calendar Months -or- 6 Calendar Years	Verify that the station battery can perform as manufactured by evaluating cell/unit measurements indicative of battery performance (e.g. internal ohmic values or float current) against the station battery baseline. -or- Verify that the station battery can perform as manufactured by conducting a performance or modified performance capacity test of the entire battery bank.

Table 1-4(b)

Component Type – Protection System Station dc Supply Using Valve-Regulated Lead-Acid (VRLA) Batteries
Excluding distributed UFLS and distributed UVLS (see Table 3)

Protection System Station dc supply used only for non-BES interrupting devices for RAS, non-distributed UFLS systems, or non-distributed UVLS systems is excluded (see Table 1-4(e)).

Component Attributes	Maximum Maintenance Interval	Maintenance Activities
Protection System Station dc supply with Valve Regulated Lead-Acid (VRLA) batteries not having monitoring attributes of Table 1-4(f).	4 Calendar Months	Verify: • Station dc supply voltage Inspect: • For unintentional grounds
	6 Calendar Months	Inspect: • Condition of all individual units by measuring battery cell/unit internal ohmic values.
	18 Calendar Months	Verify: • Float voltage of battery charger • Battery continuity • Battery terminal connection resistance • Battery intercell or unit-to-unit connection resistance Inspect: • Physical condition of battery rack

Table 1-4(b) Component Type – Protection System Station dc Supply Using Valve-Regulated Lead-Acid (VRLA) Batteries Excluding distributed UFLS and distributed UVLS (see Table 3) Protection System Station dc supply used only for non-BES interrupting devices for RAS, non-distributed UFLS systems, or non-distributed UVLS systems is excluded (see Table 1-4(e)).		
Component Attributes	**Maximum Maintenance Interval**	**Maintenance Activities**
	6 Calendar Months -or- 3 Calendar Years	Verify that the station battery can perform as manufactured by evaluating cell/unit measurements indicative of battery performance (e.g. internal ohmic values or float current) against the station battery baseline. -or- Verify that the station battery can perform as manufactured by conducting a performance or modified performance capacity test of the entire battery bank.

Table 1-4(c) Component Type – Protection System Station dc Supply Using Nickel-Cadmium (NiCad) Batteries Excluding distributed UFLS and distributed UVLS (see Table 3) Protection System Station dc supply used only for non-BES interrupting devices for RAS, non-distributed UFLS system, or non-distributed UVLS systems is excluded (see Table 1-4(e)).		
Component Attributes	**Maximum Maintenance Interval**	**Maintenance Activities**
Protection System Station dc supply **Nickel-Cadmium (NiCad) batteries** not having monitoring attributes of Table 1-4(f).	4 Calendar Months	Verify: • Station dc supply voltage Inspect: • Electrolyte level • For unintentional grounds
	18 Calendar Months	Verify: • Float voltage of battery charger • Battery continuity • Battery terminal connection resistance • Battery intercell or unit-to-unit connection resistance Inspect: • Cell condition of all individual battery cells. • Physical condition of battery rack

Table 1-4(c) Component Type – Protection System Station dc Supply Using Nickel-Cadmium (NiCad) Batteries Excluding distributed UFLS and distributed UVLS (see Table 3) Protection System Station dc supply used only for non-BES interrupting devices for RAS, non-distributed UFLS system, or non-distributed UVLS systems is excluded (see Table 1-4(e)).		
Component Attributes	Maximum Maintenance Interval	Maintenance Activities
	6 Calendar Years	Verify that the station battery can perform as manufactured by conducting a performance or modified performance capacity test of the entire battery bank.

Table 1-4(d) Component Type – Protection System Station dc Supply Using Non Battery Based Energy Storage Excluding distributed UFLS and distributed UVLS (see Table 3) Protection System Station dc supply used only for non-BES interrupting devices for RAS, non-distributed UFLS system, or non-distributed UVLS systems is excluded (see Table 1-4(e)).		
Component Attributes	**Maximum Maintenance Interval**	**Maintenance Activities**
Any Protection System station dc supply not using a battery and not having monitoring attributes of Table 1-4(f).	4 Calendar Months	Verify: • Station dc supply voltage Inspect: • For unintentional grounds
	18 Calendar Months	Inspect: Condition of non-battery based dc supply
	6 Calendar Years	Verify that the dc supply can perform as manufactured when ac power is not present.

Table 1-4(e) Component Type – Protection System Station dc Supply for non-BES Interrupting Devices for RAS, non-distributed UFLS, and non-distributed UVLS systems		
Component Attributes	**Maximum Maintenance Interval**	**Maintenance Activities**
Any Protection System dc supply used for tripping only non-BES interrupting devices as part of a RAS, non-distributed UFLS, or non-distributed UVLS system and not having monitoring attributes of Table 1-4(f).	When control circuits are verified (See Table 1-5)	Verify Station dc supply voltage.

Table 1-4(f) Exclusions for Protection System Station dc Supply Monitoring Devices and Systems		
Component Attributes	**Maximum Maintenance Interval**	**Maintenance Activities**
Any station dc supply with high and low voltage monitoring and alarming of the battery charger voltage to detect charger overvoltage and charger failure (See Table 2).	No periodic maintenance specified	No periodic verification of station dc supply voltage is required.
Any battery based station dc supply with electrolyte level monitoring and alarming in every cell (See Table 2).		No periodic inspection of the electrolyte level for each cell is required.
Any station dc supply with unintentional dc ground monitoring and alarming (See Table 2).		No periodic inspection of unintentional dc grounds is required.
Any station dc supply with charger float voltage monitoring and alarming to ensure correct float voltage is being applied on the station dc supply (See Table 2).		No periodic verification of float voltage of battery charger is required.
Any battery based station dc supply with monitoring and alarming of battery string continuity (See Table 2).		No periodic verification of the battery continuity is required.
Any battery based station dc supply with monitoring and alarming of the intercell and/or terminal connection detail resistance of the entire battery (See Table 2).		No periodic verification of the intercell and terminal connection resistance is required.
Any Valve Regulated Lead-Acid (VRLA) or Vented Lead-Acid (VLA) station battery with internal ohmic value or float current monitoring and alarming, and evaluating present values relative to baseline internal ohmic values for every cell/unit (See Table 2).		No periodic evaluation relative to baseline of battery cell/unit measurements indicative of battery performance is required to verify the station battery can perform as manufactured.
Any Valve Regulated Lead-Acid (VRLA) or Vented Lead-Acid (VLA) station battery with monitoring and alarming of each cell/unit internal ohmic value (See Table 2).		No periodic inspection of the condition of all individual units by measuring battery cell/unit internal ohmic values of a station VRLA or Vented Lead-Acid (VLA) battery is required.

Table 1-5 Component Type - Control Circuitry Associated With Protective Functions Excluding distributed UFLS and distributed UVLS (see Table 3), Automatic Reclosing (see Table 4), and Sudden Pressure Relaying (see Table 5) Note: Table requirements apply to all Control Circuitry Components of Protection Systems, and RAS except as noted.		
Component Attributes	**Maximum Maintenance Interval**	**Maintenance Activities**
Trip coils or actuators of circuit breakers, interrupting devices, or mitigating devices (regardless of any monitoring of the control circuitry).	6 Calendar Years	Verify that each trip coil is able to operate the circuit breaker, interrupting device, or mitigating device.
Electromechanical lockout devices which are directly in a trip path from the protective relay to the interrupting device trip coil (regardless of any monitoring of the control circuitry).	6 Calendar Years	Verify electrical operation of electromechanical lockout devices.
Unmonitored control circuitry associated with RAS. (See Table 4-2(b) for RAS which include Automatic Reclosing.)	12 Calendar Years	Verify all paths of the control circuits essential for proper operation of the RAS.
Unmonitored control circuitry associated with protective functions inclusive of all auxiliary relays.	12 Calendar Years	Verify all paths of the trip circuits inclusive of all auxiliary relays through the trip coil(s) of the circuit breakers or other interrupting devices.
Control circuitry associated with protective functions and/or RAS whose integrity is monitored and alarmed (See Table 2).	No periodic maintenance specified	None.

Table 2 – Alarming Paths and Monitoring **In Tables 1-1 through 1-5, Table 3, Tables 4-1 through 4-2, and Table 5 alarm attributes used to justify extended maximum maintenance intervals and/or reduced maintenance activities are subject to the following maintenance requirements**		
Component Attributes	**Maximum Maintenance Interval**	**Maintenance Activities**
Any alarm path through which alarms in Tables 1-1 through 1-5, Table 3, Tables 4-1 through 4-2, and Table 5 are conveyed from the alarm origin to the location where corrective action can be initiated, and not having all the attributes of the "Alarm Path with monitoring" category below. Alarms are reported within 24 hours of detection to a location where corrective action can be initiated.	12 Calendar Years	Verify that the alarm path conveys alarm signals to a location where corrective action can be initiated.
Alarm Path with monitoring: The location where corrective action is taken receives an alarm within 24 hours for failure of any portion of the alarming path from the alarm origin to the location where corrective action can be initiated.	No periodic maintenance specified	None.

Table 3

Maintenance Activities and Intervals for distributed UFLS and distributed UVLS Systems

Component Attributes	Maximum Maintenance Interval	Maintenance Activities
Any unmonitored protective relay not having all the monitoring attributes of a category below.	6 Calendar Years	Verify that settings are as specified. For non-microprocessor relays: • Test and, if necessary calibrate. For microprocessor relays: • Verify operation of the relay inputs and outputs that are essential to proper functioning of the Protection System. • Verify acceptable measurement of power system input values.
Monitored microprocessor protective relay with the following: • Internal self-diagnosis and alarming (See Table 2). • Voltage and/or current waveform sampling three or more times per power cycle, and conversion of samples to numeric values for measurement calculations by microprocessor electronics. Alarming for power supply failure (See Table 2).	12 Calendar Years	Verify: • Settings are as specified. • Operation of the relay inputs and outputs that are essential to proper functioning of the Protection System. • Acceptable measurement of power system input values
Monitored microprocessor protective relay with preceding row attributes and the following: • Ac measurements are continuously verified by comparison to an independent ac measurement source, with alarming for excessive error (See Table 2).	12 Calendar Years	Verify only the unmonitored relay inputs and outputs that are essential to proper functioning of the Protection System.

Table 3 Maintenance Activities and Intervals for distributed UFLS and distributed UVLS Systems		
Component Attributes	**Maximum Maintenance Interval**	**Maintenance Activities**
• Some or all binary or status inputs and control outputs are monitored by a process that continuously demonstrates ability to perform as designed, with alarming for failure (See Table 2). Alarming for change of settings (See Table 2).		
Voltage and/or current sensing devices associated with UFLS or UVLS systems.	12 Calendar Years	Verify that current and/or voltage signal values are provided to the protective relays.
Protection System dc supply for tripping non-BES interrupting devices used only for a UFLS or UVLS system.	12 Calendar Years	Verify Protection System dc supply voltage.
Control circuitry between the UFLS or UVLS relays and electromechanical lockout and/or tripping auxiliary devices (excludes non-BES interrupting device trip coils).	12 Calendar Years	Verify the path from the relay to the lockout and/or tripping auxiliary relay (including essential supervisory logic).
Electromechanical lockout and/or tripping auxiliary devices associated only with UFLS or UVLS systems (excludes non-BES interrupting device trip coils).	12 Calendar Years	Verify electrical operation of electromechanical lockout and/or tripping auxiliary devices.
Control circuitry between the electromechanical lockout and/or tripping auxiliary devices and the non-BES interrupting devices in UFLS or UVLS systems, or between UFLS or UVLS relays (with no interposing electromechanical lockout or auxiliary device) and the non-BES interrupting devices (excludes non-BES interrupting device trip coils).	No periodic maintenance specified	None.
Trip coils of non-BES interrupting devices in UFLS or UVLS systems.	No periodic maintenance specified	None.

Table 4-1

Maintenance Activities and Intervals for Automatic Reclosing Components

Component Type – Reclosing Relay

Component Attributes	Maximum Maintenance Interval	Maintenance Activities
Any unmonitored reclosing relay not having all the monitoring attributes of a category below.	6 Calendar Years	Verify that settings are as specified. For non-microprocessor relays: • Test and, if necessary calibrate For microprocessor relays: • Verify operation of the relay inputs and outputs that are essential to proper functioning of the Automatic Reclosing.
Monitored microprocessor reclosing relay with the following: • Internal self-diagnosis and alarming (See Table 2). • Alarming for power supply failure (See Table 2).	12 Calendar Years	Verify: • Settings are as specified. • Operation of the relay inputs and outputs that are essential to proper functioning of the Automatic Reclosing.

Table 4-2(a) Maintenance Activities and Intervals for Automatic Reclosing Components Component Type – Control Circuitry Associated with Reclosing Relays that are NOT an Integral Part of an RAS		
Component Attributes	**Maximum Maintenance Interval**	**Maintenance Activities**
Unmonitored Control circuitry associated with Automatic Reclosing that is not an integral part of an RAS.	12 Calendar Years	Verify that Automatic Reclosing, upon initiation, does not issue a premature closing command to the close circuitry.
Control circuitry associated with Automatic Reclosing that is not part of an RAS and is monitored and alarmed for conditions that would result in a premature closing command. (See Table 2)	No periodic maintenance specified	None.

Table 4-2(b) Maintenance Activities and Intervals for Automatic Reclosing Components Component Type – Control Circuitry Associated with Reclosing Relays that ARE an Integral Part of an RAS		
Component Attributes	**Maximum Maintenance Interval**	**Maintenance Activities**
Close coils or actuators of circuit breakers or similar devices that are used in conjunction with Automatic Reclosing as part of an RAS (regardless of any monitoring of the control circuitry).	6 Calendar Years	Verify that each close coil or actuator is able to operate the circuit breaker or mitigating device.
Unmonitored close control circuitry associated with Automatic Reclosing used as an integral part of an RAS.	12 Calendar Years	Verify all paths of the control circuits associated with Automatic Reclosing that are essential for proper operation of the RAS.
Control circuitry associated with Automatic Reclosing that is an integral part of an RAS whose integrity is monitored and alarmed. (See Table 2)	No periodic maintenance specified	None.

Table 5 Maintenance Activities and Intervals for Sudden Pressure Relaying Note: In cases where Components of Sudden Pressure Relaying are common to Components listed in Table 1-5, the Components only need to be tested once during a distinct maintenance interval.		
Component Attributes	**Maximum Maintenance Interval**	**Maintenance Activities**
Any fault pressure relay.	6 Calendar Years	Verify the pressure or flow sensing mechanism is operable.
Electromechanical lockout devices which are directly in a trip path from the fault pressure relay to the interrupting device trip coil (regardless of any monitoring of the control circuitry).	6 Calendar Years	Verify electrical operation of electromechanical lockout devices.
Unmonitored ~~C~~control circuitry associated with Sudden Pressure Relaying.	12 Calendar Years	Verify all paths of the trip circuits inclusive of all auxiliary relays through the trip coil(s) of the circuit breakers or other interrupting devices.
Control circuitry associated with Sudden Pressure Relaying whose integrity is monitored and alarmed (See Table 2).	No periodic maintenance specified	None.

PRC-005 — Attachment A

Criteria for a Performance-Based Protection System Maintenance Program

Purpose: To establish a technical basis for initial and continued use of a performance-based Protection System Maintenance Program (PSMP).

To establish the technical justification for the initial use of a performance-based PSMP:

1. Develop a list with a description of Components included in each designated Segment, with a minimum Segment population of 60 Components.
2. Maintain the Components in each Segment according to the time-based maximum allowable intervals established in Tables 1-1 through 1-5, Table 3, Tables 4-1 through 4-2, and Table 5 until results of maintenance activities for the Segment are available for a minimum of 30 individual Components of the Segment.
3. Document the maintenance program activities and results for each Segment, including maintenance dates and Countable Events for each included Component.
4. Analyze the maintenance program activities and results for each Segment to determine the overall performance of the Segment and develop maintenance intervals.
5. Determine the maximum allowable maintenance interval for each Segment such that the Segment experiences Countable Events on no more than 4% of the Components within the Segment, for the greater of either the last 30 Components maintained or all Components maintained in the previous year.

To maintain the technical justification for the ongoing use of a performance-based PSMP:

1. At least annually, update the list of Components and Segments and/or description if any changes occur within the Segment.
2. Perform maintenance on the greater of 5% of the Components (addressed in the performance based PSMP) in each Segment or 3 individual Components within the Segment in each year.
3. For the prior year, analyze the maintenance program activities and results for each Segment to determine the overall performance of the Segment.
4. Using the prior year's data, determine the maximum allowable maintenance interval for each Segment such that the Segment experiences Countable Events on no more than 4% of the Components within the Segment, for the greater of either the last 30 Components maintained or all Components maintained in the previous year.

If the Components in a Segment maintained through a performance-based PSMP experience 4% or more Countable Events, develop, document, and implement an action plan to reduce the Countable Events to less than 4% of the Segment population within 3 years.

Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Development Steps Completed

1. SAR posted for comment February 13, 2014 – March 14, 2014.
2. ~~SC authorized moving the SAR forward to standard development (SC meeting date when authorized).~~
2. The draft standard was posted for a 45-day concurrent comment and ballot period of April 17, 2014–June 3, 2014.
3. The draft standard was posted for a 45-day additional comment and ballot period of July 30 – September 12, 2014

Description of Current Draft

~~(Describe the type of action associated with this posting such as 30-day informal comment period, 30-day formal comment period, 45 day formal comment period with parallel initial ballot, 30-day formal comment period with parallel successive ballot, recirculation ballot)~~

The Protection System Maintenance and Testing Standard Drafting Team (PSMT SDT) is posting draft 3 of PRC-005-4 for a 10-day final ballot.

This draft contains the technical content of the standard. A parallel effort in the Project 2014-01, Standards Applicability for Dispersed Generation Resources, will post an applicability change to PRC-005-2 and PRC-005-3 for comment and ballot.

Anticipated Actions	Anticipated Date
45-day Formal Comment Period with Parallel Ballot	April ~~14 – May 28~~17 – June 2, 2014
45-day Additional Formal Comment Period with Parallel ~~Successive~~ Ballot (if necessary)	July 30 – September 12, 2014
Final ballot	October 20, 2014
BOT adoption	November 13, 2014

Definitions of Terms Used in Standard

This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the Reliability Standards Glossary of Terms (Glossary) are not repeated here. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, this defined term will be removed from the individual standard and added to the Glossary.

Protection System Maintenance Program (PSMP) — An ongoing program by which Protection System, Automatic Reclosing, and Sudden Pressure Relaying Components are kept in working order and proper operation of malfunctioning components is restored. A maintenance program for a specific Component includes one or more of the following activities:

- Verify — Determine that the Component is functioning correctly.
- Monitor — Observe the routine in-service operation of the Component.
- Test — Apply signals to a Component to observe functional performance or output behavior, or to diagnose problems.
- Inspect — Examine for signs of Component failure, reduced performance or degradation.
- Calibrate — Adjust the operating threshold or measurement accuracy of a measuring element to meet the intended performance requirement.

See Section A.6, Definitions Used in this Standard, for additional definitions that are new or modified for use within this standard.

When this standard has received ballot approval, the text boxes will be moved to the Application Guidelines Section of the Standard.

A. Introduction

1. **Title:** **Protection System~~ and~~, Automatic Reclosing~~ Maintenance~~, and Sudden Pressure Relaying Maintenance**
2. **Number: PRC-005-~~3~~4**
3. **Purpose:** To document and implement programs for the maintenance of all Protection Systems~~ and~~, Automatic Reclosing, and Sudden Pressure Relaying affecting the reliability of the Bulk Electric System (BES) so that they are kept in working order.

Rationale for Applicability Section: This section does not reflect the applicability changes that will be proposed by the Project 2014-01 Standards Applicability for Dispersed Generation Resources standards drafting team. The changes in this posted version and those being made by the Project 2014-01 standards drafting team do not overlap.

Additionally, to align with ongoing NERC standards development in Project 2010-05.2: Special Protection Systems, the term “Special Protection Systems” in PRC-005-4 was replaced by the term “Remedial Action Schemes.” These terms are synonymous in the NERC Glossary of Terms.

4. Applicability:

4.1. Functional Entities:

4.1.1 Transmission Owner

4.1.2 Generator Owner

4.1.3 Distribution Provider

4.2. Facilities:

4.2.1 Protection Systems and Sudden Pressure Relaying that are installed for the purpose of detecting Faults on BES Elements (lines, buses, transformers, etc.)

4.2.2 Protection Systems used for underfrequency load-shedding systems installed per ERO underfrequency load-shedding requirements.

4.2.3 Protection Systems used for undervoltage load-shedding systems installed to prevent system voltage collapse or voltage instability for BES reliability.

4.2.4 Protection Systems installed as a ~~Special Protection System (SPS~~Remedial Action Scheme (RAS) for BES reliability.

4.2.5 Protection Systems and Sudden Pressure Relaying for generator Facilities that are part of the BES, including:

4.2.5.1 Protection Systems that act to trip the generator either directly or via lockout or auxiliary tripping relays.

4.2.5.2 Protection Systems and Sudden Pressure Relaying for generator step-up transformers for generators that are part of the BES.

4.2.5.3 Protection Systems and Sudden Pressure Relaying for transformers connecting aggregated generation, where the aggregated generation is part of the BES (e.g., transformers connecting facilities such as wind-farms to the BES).

4.2.5.4 Protection Systems and Sudden Pressure Relaying for station service or excitation transformers connected to the generator bus of generators which are part of the BES, that act to trip the generator either directly or via lockout or tripping auxiliary relays.

4.2.6 Automatic Reclosing[1], including:

[1] Automatic Reclosing addressed in Section 4.2.6.1 and 4.2.6.2 may be excluded if the equipment owner can demonstrate that a close-in three-phase fault present for twice the normal clearing time (capturing a minimum trip-close-trip time delay) does not result in a total loss of gross generation in the Interconnection exceeding the gross capacity of the largest relevant BES generating unit ~~within the Balancing Authority Area~~ where the Automatic Reclosing is applied.

4.2.6.1 Automatic Reclosing applied on the terminals of Elements connected to the BES bus located at generating plant substations where the total installed gross generating plant capacity is greater than the gross capacity of the largest BES generating unit within the Balancing Authority Area~~.~~ or, if a member of a Reserve Sharing Group, the largest generating unit within the Reserve Sharing Group. [2]

4.2.6.2 Automatic Reclosing applied on the terminals of all BES Elements at substations one bus away from generating plants specified in Section 4.2.6.1 when the substation is less than 10 circuit-miles from the generating plant substation.

4.2.6.3. Automatic Reclosing applied as an integral part of an ~~SPS~~RAS specified in Section 4.2.4.

5. **Effective Date:** See Implementation Plan

~~**6. Background:**~~

~~7.~~6. Definitions Used in this Standard: ~~The following terms are defined for use only within PRC-005-3, and should remain with the standard upon approval rather than being moved to the Glossary of Terms.~~

Automatic Reclosing – Includes the following Components:

- Reclosing relay
- Control circuitry associated with the reclosing relay.

Sudden Pressure Relaying – A system that trips an interrupting device(s) to isolate the equipment it is monitoring and includes the following Components:

- Fault pressure relay – a mechanical relay or device that detects rapid changes in gas pressure, oil pressure, or oil flow that are indicative of Faults within liquid-filled, wire-wound equipment
- Control circuitry associated with a fault pressure relay

Unresolved Maintenance Issue – A deficiency identified during a maintenance activity that causes the ~~component~~Component to not meet the intended performance, cannot be corrected during the maintenance interval, and requires follow-up corrective action.

[2] The largest BES generating unit within the Balancing Authority Area or the largest generating unit within the Reserve Sharing Group, as applicable, is subject to change. As a result of such a change, the Automatic Reclosing Components subject to the standard could change effective on the date of such change.

Segment – Components of a consistent design standard, or a particular model or type from a single manufacturer that typically share other common elements. Consistent performance is expected across the entire population of a Segment. A Segment must contain at least sixty (60) individual Components.

Component Type – ~~Either any~~

- Any one of the five specific elements of ~~the~~a Protection System~~ definition or any~~.
- Any one of the two specific elements of ~~the~~ Automatic Reclosing~~ definition.~~.

~~**Component** – A Component is any individual discrete piece of equipment included in a Protection System or in Automatic Reclosing, including but not limited to a protective relay, reclosing relay, or current sensing device. The designation of what constitutes a control circuit Component is dependent upon how an entity performs and tracks the testing of the control circuitry. Some entities test their control circuits on a breaker basis whereas others test their circuitry on a local zone of protection basis. Thus, entities are allowed the latitude to designate their own definitions of control circuit Components. Another example of where the entity has some discretion on determining what constitutes a single Component is the voltage and current sensing devices, where the entity may choose either to designate a full three-phase set of such devices or a single device as a single Component.~~

- Any one of the two specific elements of Sudden Pressure Relaying.

Rationale for the deletion of part of the definition of Component: The SDT determined that it was explanatory in nature and adequately addressed in the Supplementary Reference and FAQ Document.

Component – Any individual discrete piece of equipment included in a Protection System, Automatic Reclosing, or Sudden Pressure Relaying.

Countable Event – A failure of a Component requiring repair or replacement, any condition discovered during the maintenance activities in Tables 1-1 through 1-5, Table 3, ~~and~~ Tables 4-1 through 4-2, and Table 5, which requires corrective action or a Protection System Misoperation attributed to hardware failure or calibration failure. Misoperations due to product design errors, software errors, relay settings different from specified settings, Protection System Component~~ or~~, Automatic Reclosing, or Sudden Pressure Relaying configuration or application errors are not included in Countable Events.

B. Requirements and Measures

R1. Each Transmission Owner, Generator Owner, and Distribution Provider shall establish a Protection System Maintenance Program (PSMP) for its Protection Systems~~ and~~, Automatic Reclosing, and Sudden Pressure Relaying identified in ~~Facilities~~ Section 4.2, Facilities. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

The PSMP shall:

1.1. Identify which maintenance method (time-based, performance-based per PRC-005 Attachment A, or a combination) is used to address each Protection System ~~and~~, Automatic Reclosing, and Sudden Pressure Relaying Component Type. All batteries associated with the station dc supply Component Type of a Protection System shall be included in a time-based program as described in Table 1-4 and Table 3.

1.2. Include the applicable monitored Component attributes applied to each Protection System ~~and~~, Automatic Reclosing, and Sudden Pressure Relaying Component Type consistent with the maintenance intervals specified in Tables 1-1 through 1-5, Table 2, Table 3, ~~and~~ Table 4-1 through 4-2, and Table 5 where monitoring is used to extend the maintenance intervals beyond those specified for unmonitored Protection System ~~and~~, Automatic Reclosing, and Sudden Pressure Relaying Components.

M1. Each Transmission Owner, Generator Owner and Distribution Provider shall have a documented Protection System Maintenance Program in accordance with Requirement R1.

For each Protection System ~~and~~, Automatic Reclosing, and Sudden Pressure Relaying Component Type, the documentation shall include the type of maintenance method applied (time-based, performance-based, or a combination of these maintenance methods), and shall include all batteries associated with the station dc supply Component Types in a time-based program as described in Table 1-4 and Table 3. (Part 1.1)

For Component Types that use monitoring to extend the maintenance intervals, the responsible entity(s) shall have evidence for each Protection System ~~and~~, Automatic Reclosing, and Sudden Pressure Relaying Component Type (such as manufacturer's specifications or engineering drawings) of the appropriate monitored Component attributes as specified in Tables 1-1 through 1-5, Table 2, Table 3, ~~and~~ Table 4-1 through 4-2, and Table 5. (Part 1.2)

R2. Each Transmission Owner, Generator Owner, and Distribution Provider that uses performance-based maintenance intervals in its PSMP shall follow the procedure established in PRC-005 Attachment A to establish and maintain its performance-based intervals. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

M2. Each Transmission Owner, Generator Owner, and Distribution Provider that uses performance-based maintenance intervals shall have evidence that its current performance-based maintenance program(s) is in accordance with Requirement R2, which may include, but is not limited to, Component lists, dated maintenance records, and dated analysis records and results.

~~Rationale for R3:~~ **Rationale for R3 Part 3.1:** In the last posting, the SDT included language in the standard that was originally in the implementation plan that required completion of maintenance activities within three years for newly-identified Automatic Reclosing Components following a notification under Requirement R6, which has been removed. After further discussion, the SDT determined that a separate shorter timeframe for maintenance of newly-identified Automatic Reclosing Components created unnecessary complication within the standard. The SDT agreed that entities should be responsible for maintaining the Automatic Reclosing Components subject to the standard, whether existing, newly added or newly within scope based on a change in the largest generating unit in the BA or, if a member of a Reserve Sharing Group, the largest generating unit within the Reserve Sharing Group according to the timeframes in the maintenance tables. Therefore, 3.1 and its subparts have been removed and have not been reinserted into the implementation plan.

R3. Each Transmission Owner, Generator Owner, and Distribution Provider that utilizes time-based maintenance program(s) shall maintain its Protection System ~~and~~, Automatic Reclosing, and Sudden Pressure Relaying Components that are included within the time-based maintenance program in accordance with the minimum maintenance activities and maximum maintenance intervals prescribed within Tables 1-1 through 1-5, Table 2, Table 3, ~~and~~ Table 4-1 through 4-2, and Table 5. *[Violation Risk Factor: High] [Time Horizon: Operations Planning]*

M3. Each Transmission Owner, Generator Owner, and Distribution Provider that utilizes time-based maintenance program(s) shall have evidence that it has maintained its Protection System ~~and~~, Automatic Reclosing, and Sudden Pressure Relaying Components included within its time-based program in accordance with Requirement R3. The evidence may include, but is not limited to, dated maintenance records, dated maintenance summaries, dated check-off lists, dated inspection records, or dated work orders.

~~Rationale for R4:~~ **Rationale for R4 Part 4.1:** In the last posting, the SDT included language in the standard that was originally in the implementation plan that required completion of maintenance activities within three years for newly-identified Automatic Reclosing Components following a notification under Requirement R6, which has been removed. After further discussion, the SDT determined that a separate shorter timeframe for maintenance of newly-identified Automatic Reclosing Components created unnecessary complication within the standard. The SDT agreed that entities should be responsible for maintaining the Automatic Reclosing Components subject to the standard, whether existing, newly added or newly within scope based on a change in the largest generating unit in the BA or, if a member of a Reserve Sharing Group, the largest generating unit within the Reserve Sharing Group according to the timeframes in the maintenance tables. Therefore, 4.1 and its subparts have been removed and have not been reinserted into the implementation plan.

R4. Each Transmission Owner, Generator Owner, and Distribution Provider that utilizes performance-based maintenance program(s) in accordance with Requirement R2 shall implement and follow its PSMP for its Protection System~~ and~~, Automatic Reclosing, and Sudden Pressure Relaying Components that are included within the performance-based program(s). *[Violation Risk Factor: High] [Time Horizon: Operations Planning]*

M4. Each Transmission Owner, Generator Owner, and Distribution Provider that utilizes performance-based maintenance intervals in accordance with Requirement R2 shall have evidence that it has implemented the Protection System Maintenance Program for the Protection System~~ and~~, Automatic Reclosing, and Sudden Pressure Relaying Components included in its performance-based program in accordance with Requirement R4. The evidence may include, but is not limited to, dated maintenance records, dated maintenance summaries, dated check-off lists, dated inspection records, or dated work orders.

R5. Each Transmission Owner, Generator Owner, and Distribution Provider shall demonstrate efforts to correct identified Unresolved Maintenance Issues. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

M5. Each Transmission Owner, Generator Owner, and Distribution Provider shall have evidence that it has undertaken efforts to correct identified Unresolved Maintenance Issues in accordance with Requirement R5. The evidence may include, but is not limited to, work orders, replacement Component orders, invoices, project schedules with completed milestones, return material authorizations (RMAs) or purchase orders.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

As defined in the NERC Rules of Procedure, "Compliance Enforcement Authority" means NERC or the Regional Entity in their respective roles of monitoring and enforcing compliance with the NERC Reliability Standards.

1.2. Evidence Retention

The following evidence retention periods identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

The Transmission Owner, Generator Owner, and Distribution Provider shall each keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

For Requirement R1, the Transmission Owner, Generator Owner, and Distribution Provider shall each keep its current dated Protection System Maintenance Program, as well as any superseded versions since the preceding compliance audit, including the documentation that specifies the type of maintenance program applied for each Protection System, Automatic Reclosing, or Sudden Pressure Relaying Component Type.

For Requirement R2, Requirement R3, ~~Requirement R4,~~ and Requirement ~~R5~~R4, in cases where the interval of the maintenance activity is longer than the audit cycle, the Transmission Owner, Generator Owner, and Distribution Provider shall each keep documentation of the ~~two~~ most recent ~~performances~~performance of ~~each distinct~~that maintenance activity for the Protection System~~ or~~, Automatic Reclosing, or Sudden Pressure Relaying Component~~, or~~. In cases where the interval of the maintenance activity is shorter than the audit cycle, documentation of all performances ~~of each distinct~~(in accordance with the tables) of that maintenance activity for the Protection System~~ or~~, Automatic Reclosing, or Sudden Pressure Relaying Component since the previous scheduled audit date~~, whichever is longer~~ shall be retained.
For Requirement R5 the Transmission Owner, Generator Owner, and Distribution Provider shall each keep documentation of Unresolved Maintenance Issues identified by the entity since the last audit, including all that were resolved since the last audit.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.3. Compliance Monitoring and Assessment Processes:

Compliance Audits

Self-Certifications

Spot Checking

Compliance Violation Investigations

Self-Reporting

Complaints

1.4. Additional Compliance Information

None

Table of Compliance Elements

Requirement Number	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	The~~ responsible~~ entity's PSMP failed to specify whether one Component Type is being addressed by time-based or performance-based maintenance, or a combination of both~~.~~ (Part 1.1~~)~~). ~~OR~~ ~~The responsible entity's PSMP failed to include applicable station batteries in a time-based program. (Part 1.1)~~	The~~ responsible~~ entity's PSMP failed to specify whether two Component Types are being addressed by time-based or performance-based maintenance, or a combination of both~~.~~ (Part 1.1~~)~~).	The~~ responsible~~ entity's PSMP failed to specify whether three Component Types are being addressed by time-based or performance-based maintenance, or a combination of both. (Part 1.1). OR The~~ responsible~~ entity's PSMP failed to include the applicable monitoring attributes applied to each Component Type consistent with the maintenance intervals specified in Tables 1-1 through 1-5, Table 2, Table 3, ~~and~~ Tables 4-1 through 4-2, and Table 5 where monitoring is used to extend the maintenance intervals beyond those specified for unmonitored Components~~.~~ (Part 1.2).	The ~~responsible~~ entity failed to establish a PSMP. OR The~~ responsible~~ entity's PSMP failed to specify whether four or more Component Types are being addressed by time-based or performance-based maintenance, or a combination of both~~. (Part 1.1).~~ (Part 1.1). OR The entity's PSMP failed to include applicable station batteries in a time-based program (Part 1.1).
R2	The~~ responsible~~ entity uses performance-based maintenance intervals in its PSMP but failed to reduce Countable Events to no more than 4% within three years.	NA	The~~ responsible~~ entity uses performance-based maintenance intervals in its PSMP but failed to reduce Countable Events to no more than 4% within four years.	The~~ responsible~~ entity uses performance-based maintenance intervals in its PSMP but: 1) Failed to establish the technical justification described within Requirement R2 for the initial use of the performance-based PSMP OR 2) Failed to reduce Countable Events to no more than 4% within five years

Requirement Number	Lower VSL	Moderate VSL	High VSL	Severe VSL
				OR 3) Maintained a Segment with less than 60 Components OR 4) Failed to: • Annually update the list of Components, OR • Annually perform maintenance on the greater of 5% of the Segment population or 3 Components, OR • Annually analyze the program activities and results for each Segment.
R3	For Components included within a time-based maintenance program, the~~ responsible~~ entity failed to maintain 5% or less of the total Components included within a specific Component Type~~,~~ in accordance with the minimum maintenance activities and maximum maintenance intervals prescribed within Tables 1-1 through 1-5, Table 2, Table 3, ~~and~~ Tables 4-1 through 4-2~~.~~, and Table 5.	For Components included within a time-based maintenance program, the~~ responsible~~ entity failed to maintain more than 5% but 10% or less of the total Components included within a specific Component Type~~,~~ in accordance with the minimum maintenance activities and maximum maintenance intervals prescribed within Tables 1-1 through 1-5, Table 2, Table 3, ~~and~~ Tables 4-1 through 4-2~~.~~, and Table 5.	For Components included within a time-based maintenance program, the~~ responsible~~ entity failed to maintain more than 10% but 15% or less of the total Components included within a specific Component Type~~,~~ in accordance with the minimum maintenance activities and maximum maintenance intervals prescribed within Tables 1-1 through 1-5, Table 2, Table 3, ~~and~~ Tables 4-1 through 4-2~~.~~, and Table 5.	For Components included within a time-based maintenance program, the~~ responsible~~ entity failed to maintain more than 15% of the total Components included within a specific Component Type~~,~~ in accordance with the minimum maintenance activities and maximum maintenance intervals prescribed within Tables 1-1 through 1-5, Table 2, Table 3, ~~and~~ Tables 4-1 through 4-2~~.~~, and Table 5.

Requirement Number	Lower VSL	Moderate VSL	High VSL	Severe VSL
R4	For Components included within a performance-based maintenance program, the ~~responsible~~ entity failed to maintain 5% or less of the annual scheduled maintenance for a specific Component Type in accordance with their performance-based PSMP.	For Components included within a performance-based maintenance program, the ~~responsible~~ entity failed to maintain more than 5% but 10% or less of the annual scheduled maintenance for a specific Component Type in accordance with their performance-based PSMP.	For Components included within a performance-based maintenance program, the ~~responsible~~ entity failed to maintain more than 10% but 15% or less of the annual scheduled maintenance for a specific Component Type in accordance with their performance-based PSMP.	For Components included within a performance-based maintenance program, the ~~responsible~~ entity failed to maintain more than 15% of the annual scheduled maintenance for a specific Component Type in accordance with their performance-based PSMP.
R5	The ~~responsible~~ entity failed to undertake efforts to correct 5 or fewer identified Unresolved Maintenance Issues.	The ~~responsible~~ entity failed to undertake efforts to correct greater than 5~~,~~ but less than or equal to 10 identified Unresolved Maintenance Issues.	The ~~responsible~~ entity failed to undertake efforts to correct greater than 10~~,~~ but less than or equal to 15 identified Unresolved Maintenance Issues.	The ~~responsible~~ entity failed to undertake efforts to correct greater than 15 identified Unresolved Maintenance Issues.

D. Regional Variances

None.

E. Interpretations

None.

F. Supplemental Reference ~~Document~~Documents

The following documents present a detailed discussion about determination of maintenance intervals and other useful information regarding establishment of a maintenance program.

1. *Supplementary Reference and FAQ - PRC-005-~~2~~4 Protection System Maintenance*~~Supplementary Reference and FAQ — March 2013.~~, Protection System Maintenance and Testing Standard Drafting Team (April 2014)
2. *Considerations for Maintenance and Testing of ~~Autoreclosing~~Auto-reclosing Schemes*~~ — ~~, NERC System Analysis and Modeling Subcommittee, and NERC System Protection and Control Subcommittee (November 2012~~.~~)
3. *Sudden Pressure Relays and Other Devices that Respond to Non-Electrical Quantities – SPCS Input for Standard Development in Response to FERC Order No. 758,* NERC System Protection and Control Subcommittee (December 2013)

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
1	December 1, 2005	1. Changed incorrect use of certain hyphens (-) to "en dash" (–) and "em dash (—)." 2. Added "periods" to items where appropriate. 3. Changed "Timeframe" to "Time Frame" in item D, 1.2.	01/20/05
1a	February 17, 2011	Added Appendix 1 - Interpretation regarding applicability of standard to protection of radially connected transformers	Project 2009-17 interpretation
1a	February 17, 2011	Adopted by Board of Trustees	
1a	September 26, 2011	FERC Order issued approving interpretation of R1 and R2 (FERC's Order is effective as of September 26, 2011)	

1.1a	February 1, 2012	Errata change: Clarified inclusion of generator interconnection Facility in Generator Owner's responsibility	Revision under Project 2010-07
1b	February 3, 2012	FERC Order issued approving interpretation of R1, R1.1, and R1.2 (FERC's Order dated March 14, 2012). Updated version from 1a to 1b.	Project 2009-10 Interpretation
1.1b	April 23, 2012	Updated standard version to 1.1b to reflect FERC approval of PRC-005-1b.	Revision under Project 2010-07

1.1b	May 9, 2012	PRC-005-1.1b was adopted by the Board of Trustees as part of Project 2010-07 (~~GOTO~~Generator Requirements at the Transmission Interface).	
2	November 7, 2012	Adopted by Board of Trustees	Project 2007-17 - Complete revision, absorbing maintenance requirements from PRC-005-1.1b, PRC-008-0, PRC-011-0, PRC-017-0
2	October 17, 2013	Errata Change: The Standards Committee approved an errata change to the implementation plan for PRC-005-2 to add the phrase "or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities;" to the second sentence under the "Retirement of Existing	
3	November 7, 2013	Adopted by the NERC Board of Trustees	Revised to address the FERC directive in Order No.758 to include Automatic Reclosing in maintenance programs.

3.1	February 12, 2014	Approved by the Standards Committee	Errata changes to correct capitalization of defined terms
X			Project 2007-17.3 – Revised to address the FERC directive in Order No. 758 to include sudden pressure relays in maintenance programs.

Table 1-1 Component Type - Protective Relay Excluding distributed UFLS and distributed UVLS (see Table 3)		
Component Attributes	**Maximum Maintenance Interval[3]**	**Maintenance Activities**
Any unmonitored protective relay not having all the monitoring attributes of a category below.	6 Calendar Years	For all unmonitored relays: • Verify that settings are as specified For non-microprocessor relays: • Test and, if necessary calibrate For microprocessor relays: • Verify operation of the relay inputs and outputs that are essential to proper functioning of the Protection System. • Verify acceptable measurement of power system input values.
Monitored microprocessor protective relay with the following: • Internal self-diagnosis and alarming (see Table 2). • Voltage and/or current waveform sampling three or more times per power cycle, and conversion of samples to numeric values for measurement calculations by microprocessor electronics. • Alarming for power supply failure (see Table 2).	12 Calendar Years	Verify: • Settings are as specified. • Operation of the relay inputs and outputs that are essential to proper functioning of the Protection System. • Acceptable measurement of power system input values.

[3] For the tables in this standard, a calendar year starts on the first day of a new year (January 1) after a maintenance activity has been completed.
For the tables in this standard, a calendar month starts on the first day of the first month after a maintenance activity has been completed.

Monitored microprocessor protective relay with preceding row attributes and the following: • Ac measurements are continuously verified by comparison to an independent ac measurement source, with alarming for excessive error (See Table 2). • Some or all binary or status inputs and control outputs are monitored by a process that continuously demonstrates ability to perform as designed, with alarming for failure (See Table 2). • Alarming for change of settings (See Table 2).	12 Calendar Years	Verify only the unmonitored relay inputs and outputs that are essential to proper functioning of the Protection System.

Table 1-2

Component Type - Communications Systems

Excluding distributed UFLS and distributed UVLS (see Table 3)

Component Attributes	Maximum Maintenance Interval	Maintenance Activities
Any unmonitored communications system necessary for correct operation of protective functions, and not having all the monitoring attributes of a category below.	4 Calendar Months	Verify that the communications system is functional.
Any unmonitored communications system necessary for correct operation of protective functions, and not having all the monitoring attributes of a category below.	6 Calendar Years	Verify that the communications system meets performance criteria pertinent to the communications technology applied (e.g. signal level, reflected power, or data error rate). Verify operation of communications system inputs and outputs that are essential to proper functioning of the Protection System.
Any communications system with continuous monitoring or periodic automated testing for the presence of the channel function, and alarming for loss of function (See Table 2).	12 Calendar Years	Verify that the communications system meets performance criteria pertinent to the communications technology applied (e.g. signal level, reflected power, or data error rate). Verify operation of communications system inputs and outputs that are essential to proper functioning of the Protection System.
Any communications system with all of the following: • Continuous monitoring or periodic automated testing for the performance of the channel using criteria pertinent to the communications technology applied (e.g. signal level, reflected power, or data error rate, and alarming for excessive performance degradation). (See Table 2) • Some or all binary or status inputs and control outputs are monitored by a process that continuously demonstrates ability to perform as designed, with alarming for failure (See Table 2).	12 Calendar Years	Verify only the unmonitored communications system inputs and outputs that are essential to proper functioning of the Protection System

Table 1-3 Component Type - Voltage and Current Sensing Devices Providing Inputs to Protective Relays Excluding distributed UFLS and distributed UVLS (see Table 3)		
Component Attributes	**Maximum Maintenance Interval**	**Maintenance Activities**
Any voltage and current sensing devices not having monitoring attributes of the category below.	12 Calendar Years	Verify that current and voltage signal values are provided to the protective relays.
Voltage and Current Sensing devices connected to microprocessor relays with AC measurements are continuously verified by comparison of sensing input value, as measured by the microprocessor relay, to an independent ac measurement source, with alarming for unacceptable error or failure (see Table 2).	No periodic maintenance specified	None.

Table 1-4(a) Component Type – Protection System Station dc Supply Using Vented Lead-Acid (VLA) Batteries Excluding distributed UFLS and distributed UVLS (see Table 3) Protection System Station dc supply used only for non-BES interrupting devices for ~~SPS~~RAS, non-distributed UFLS systems, or non-distributed UVLS systems is excluded (see Table 1-4(e)).		
Component Attributes	**Maximum Maintenance Interval**	**Maintenance Activities**
Protection System Station dc supply using Vented Lead-Acid (VLA) batteries not having monitoring attributes of Table 1-4(f).	4 Calendar Months	Verify: • Station dc supply voltage Inspect: • Electrolyte level • For unintentional grounds
	18 Calendar Months	Verify: • Float voltage of battery charger • Battery continuity • Battery terminal connection resistance • Battery intercell or unit-to-unit connection resistance Inspect: • Cell condition of all individual battery cells where cells are visible – or measure battery cell/unit internal ohmic values where the cells are not visible • Physical condition of battery rack

Table 1-4(a) Component Type – Protection System Station dc Supply Using Vented Lead-Acid (VLA) Batteries Excluding distributed UFLS and distributed UVLS (see Table 3) Protection System Station dc supply used only for non-BES interrupting devices for ~~SPS~~RAS, non-distributed UFLS systems, or non-distributed UVLS systems is excluded (see Table 1-4(e)).		
Component Attributes	**Maximum Maintenance Interval**	**Maintenance Activities**
	18 Calendar Months -or- 6 Calendar Years	Verify that the station battery can perform as manufactured by evaluating cell/unit measurements indicative of battery performance (e.g. internal ohmic values or float current) against the station battery baseline. -or- Verify that the station battery can perform as manufactured by conducting a performance or modified performance capacity test of the entire battery bank.

Table 1-4(b) Component Type – Protection System Station dc Supply Using Valve-Regulated Lead-Acid (VRLA) Batteries Excluding distributed UFLS and distributed UVLS (see Table 3) Protection System Station dc supply used only for non-BES interrupting devices for ~~SPS~~RAS, non-distributed UFLS systems, or non-distributed UVLS systems is excluded (see Table 1-4(e)).		
Component Attributes	**Maximum Maintenance Interval**	**Maintenance Activities**
Protection System Station dc supply with Valve Regulated Lead-Acid (VRLA) batteries not having monitoring attributes of Table 1-4(f).	4 Calendar Months	Verify: • Station dc supply voltage Inspect: • For unintentional grounds
	6 Calendar Months	Inspect: • Condition of all individual units by measuring battery cell/unit internal ohmic values.
	18 Calendar Months	Verify: • Float voltage of battery charger • Battery continuity • Battery terminal connection resistance • Battery intercell or unit-to-unit connection resistance Inspect: • Physical condition of battery rack

Table 1-4(b) Component Type – Protection System Station dc Supply Using Valve-Regulated Lead-Acid (VRLA) Batteries Excluding distributed UFLS and distributed UVLS (see Table 3) Protection System Station dc supply used only for non-BES interrupting devices for ~~SPS~~RAS, non-distributed UFLS systems, or non-distributed UVLS systems is excluded (see Table 1-4(e)).		
Component Attributes	**Maximum Maintenance Interval**	**Maintenance Activities**
	6 Calendar Months -or- 3 Calendar Years	Verify that the station battery can perform as manufactured by evaluating cell/unit measurements indicative of battery performance (e.g. internal ohmic values or float current) against the station battery baseline. -or- Verify that the station battery can perform as manufactured by conducting a performance or modified performance capacity test of the entire battery bank.

<table>
<tr><th colspan="3">Table 1-4(c)
Component Type – Protection System Station dc Supply Using Nickel-Cadmium (NiCad) Batteries
Excluding distributed UFLS and distributed UVLS (see Table 3)

Protection System Station dc supply used only for non-BES interrupting devices for ~~SPS~~RAS, non-distributed UFLS system, or non-distributed UVLS systems is excluded (see Table 1-4(e)).</th></tr>
<tr><th>Component Attributes</th><th>Maximum Maintenance Interval</th><th>Maintenance Activities</th></tr>
<tr><td rowspan="2">Protection System Station dc supply Nickel-Cadmium (NiCad) batteries not having monitoring attributes of Table 1-4(f).</td><td>4 Calendar Months</td><td>Verify:
Station dc supply voltage
Inspect:
Electrolyte level
For unintentional grounds</td></tr>
<tr><td>18 Calendar Months</td><td>Verify:
Float voltage of battery charger
Battery continuity
Battery terminal connection resistance
Battery intercell or unit-to-unit connection resistance
Inspect:
Cell condition of all individual battery cells.
Physical condition of battery rack</td></tr>
</table>

Table 1-4(c) Component Type – Protection System Station dc Supply Using Nickel-Cadmium (NiCad) Batteries Excluding distributed UFLS and distributed UVLS (see Table 3) Protection System Station dc supply used only for non-BES interrupting devices for ~~SPS~~RAS, non-distributed UFLS system, or non-distributed UVLS systems is excluded (see Table 1-4(e)).		
Component Attributes	Maximum Maintenance Interval	Maintenance Activities
	6 Calendar Years	Verify that the station battery can perform as manufactured by conducting a performance or modified performance capacity test of the entire battery bank.

Table 1-4(d)

Component Type – Protection System Station dc Supply Using Non Battery Based Energy Storage

Excluding distributed UFLS and distributed UVLS (see Table 3)

Protection System Station dc supply used only for non-BES interrupting devices for ~~SPS~~RAS, non-distributed UFLS system, or non-distributed UVLS systems is excluded (see Table 1-4(e)).

Component Attributes	Maximum Maintenance Interval	Maintenance Activities
Any Protection System station dc supply not using a battery and not having monitoring attributes of Table 1-4(f).	4 Calendar Months	Verify: • Station dc supply voltage Inspect: • For unintentional grounds
	18 Calendar Months	Inspect: Condition of non-battery based dc supply
	6 Calendar Years	Verify that the dc supply can perform as manufactured when ac power is not present.

Table 1-4(e) Component Type – Protection System Station dc Supply for non-BES Interrupting Devices for ~~SPS~~RAS, non-distributed UFLS, and non-distributed UVLS systems		
Component Attributes	**Maximum Maintenance Interval**	**Maintenance Activities**
Any Protection System dc supply used for tripping only non-BES interrupting devices as part of a ~~SPS~~RAS, non-distributed UFLS, or non-distributed UVLS system and not having monitoring attributes of Table 1-4(f).	When control circuits are verified (See Table 1-5)	Verify Station dc supply voltage.

Table 1-4(f) Exclusions for Protection System Station dc Supply Monitoring Devices and Systems		
Component Attributes	**Maximum Maintenance Interval**	**Maintenance Activities**
Any station dc supply with high and low voltage monitoring and alarming of the battery charger voltage to detect charger overvoltage and charger failure (See Table 2).	No periodic maintenance specified	No periodic verification of station dc supply voltage is required.
Any battery based station dc supply with electrolyte level monitoring and alarming in every cell (See Table 2).		No periodic inspection of the electrolyte level for each cell is required.
Any station dc supply with unintentional dc ground monitoring and alarming (See Table 2).		No periodic inspection of unintentional dc grounds is required.
Any station dc supply with charger float voltage monitoring and alarming to ensure correct float voltage is being applied on the station dc supply (See Table 2).		No periodic verification of float voltage of battery charger is required.
Any battery based station dc supply with monitoring and alarming of battery string continuity (See Table 2).		No periodic verification of the battery continuity is required.
Any battery based station dc supply with monitoring and alarming of the intercell and/or terminal connection detail resistance of the entire battery (See Table 2).		No periodic verification of the intercell and terminal connection resistance is required.
Any Valve Regulated Lead-Acid (VRLA) or Vented Lead-Acid (VLA) station battery with internal ohmic value or float current monitoring and alarming, and evaluating present values relative to baseline internal ohmic values for every cell/unit (See Table 2).		No periodic evaluation relative to baseline of battery cell/unit measurements indicative of battery performance is required to verify the station battery can perform as manufactured.
Any Valve Regulated Lead-Acid (VRLA) or Vented Lead-Acid (VLA) station battery with monitoring and alarming of each cell/unit internal ohmic value (See Table 2).		No periodic inspection of the condition of all individual units by measuring battery cell/unit internal ohmic values of a station VRLA or Vented Lead-Acid (VLA) battery is required.

Table 1-5 Component Type - Control Circuitry Associated With Protective Functions Excluding distributed UFLS and distributed UVLS (see Table 3), Automatic Reclosing (see Table 4), and Sudden Pressure Relaying (see Table 5) Note: Table requirements apply to all Control Circuitry Components of Protection Systems, and ~~SPSs~~RAS except as noted.		
Component Attributes	**Maximum Maintenance Interval**	**Maintenance Activities**
Trip coils or actuators of circuit breakers, interrupting devices, or mitigating devices (regardless of any monitoring of the control circuitry).	6 Calendar Years	Verify that each trip coil is able to operate the circuit breaker, interrupting device, or mitigating device.
Electromechanical lockout devices which are directly in a trip path from the protective relay to the interrupting device trip coil (regardless of any monitoring of the control circuitry).	6 Calendar Years	Verify electrical operation of electromechanical lockout devices.
Unmonitored control circuitry associated with ~~SPS~~RAS. (See Table 4-2(b) for ~~SPS~~RAS which include Automatic Reclosing.)	12 Calendar Years	Verify all paths of the control circuits essential for proper operation of the ~~SPS~~RAS.
Unmonitored control circuitry associated with protective functions inclusive of all auxiliary relays.	12 Calendar Years	Verify all paths of the trip circuits inclusive of all auxiliary relays through the trip coil(s) of the circuit breakers or other interrupting devices.
Control circuitry associated with protective functions and/or ~~SPSs~~RAS whose integrity is monitored and alarmed (See Table 2).	No periodic maintenance specified	None.

Table 2 – Alarming Paths and Monitoring In Tables 1-1 through 1-5, Table 3, ~~and~~ Tables 4-1 through 4-2, and Table 5 alarm attributes used to justify extended maximum maintenance intervals and/or reduced maintenance activities are subject to the following maintenance requirements		
Component Attributes	**Maximum Maintenance Interval**	**Maintenance Activities**
Any alarm path through which alarms in Tables 1-1 through 1-5, Table 3, ~~and~~ Tables 4-1 through 4-2, and Table 5 are conveyed from the alarm origin to the location where corrective action can be initiated, and not having all the attributes of the "Alarm Path with monitoring" category below. Alarms are reported within 24 hours of detection to a location where corrective action can be initiated.	12 Calendar Years	Verify that the alarm path conveys alarm signals to a location where corrective action can be initiated.
Alarm Path with monitoring: The location where corrective action is taken receives an alarm within 24 hours for failure of any portion of the alarming path from the alarm origin to the location where corrective action can be initiated.	No periodic maintenance specified	None.

Table 3 Maintenance Activities and Intervals for distributed UFLS and distributed UVLS Systems		
Component Attributes	**Maximum Maintenance Interval**	**Maintenance Activities**
Any unmonitored protective relay not having all the monitoring attributes of a category below.	6 Calendar Years	Verify that settings are as specified. For non-microprocessor relays: • Test and, if necessary calibrate. For microprocessor relays: • Verify operation of the relay inputs and outputs that are essential to proper functioning of the Protection System. • Verify acceptable measurement of power system input values.
Monitored microprocessor protective relay with the following: • Internal self-~~-~~diagnosis and alarming (See Table 2). • Voltage and/or current waveform sampling three or more times per power cycle, and conversion of samples to numeric values for measurement calculations by microprocessor electronics. Alarming for power supply failure (See Table 2).	12 Calendar Years	Verify: • Settings are as specified. • Operation of the relay inputs and outputs that are essential to proper functioning of the Protection System. • Acceptable measurement of power system input values
Monitored microprocessor protective relay with preceding row attributes and the following: • Ac measurements are continuously verified by comparison to an independent ac measurement source, with alarming for excessive error (See Table 2).	12 Calendar Years	Verify only the unmonitored relay inputs and outputs that are essential to proper functioning of the Protection System.

Table 3 Maintenance Activities and Intervals for distributed UFLS and distributed UVLS Systems		
Component Attributes	**Maximum Maintenance Interval**	**Maintenance Activities**
• Some or all binary or status inputs and control outputs are monitored by a process that continuously demonstrates ability to perform as designed, with alarming for failure (See Table 2). Alarming for change of settings (See Table 2).		
Voltage and/or current sensing devices associated with UFLS or UVLS systems.	12 Calendar Years	Verify that current and/or voltage signal values are provided to the protective relays.
Protection System dc supply for tripping non-BES interrupting devices used only for a UFLS or UVLS system.	12 Calendar Years	Verify Protection System dc supply voltage.
Control circuitry between the UFLS or UVLS relays and electromechanical lockout and/or tripping auxiliary devices (excludes non-BES interrupting device trip coils).	12 Calendar Years	Verify the path from the relay to the lockout and/or tripping auxiliary relay (including essential supervisory logic).
Electromechanical lockout and/or tripping auxiliary devices associated only with UFLS or UVLS systems (excludes non-BES interrupting device trip coils).	12 Calendar Years	Verify electrical operation of electromechanical lockout and/or tripping auxiliary devices.
Control circuitry between the electromechanical lockout and/or tripping auxiliary devices and the non-BES interrupting devices in UFLS or UVLS systems, or between UFLS or UVLS relays (with no interposing electromechanical lockout or auxiliary device) and the non-BES interrupting devices (excludes non-BES interrupting device trip coils).	No periodic maintenance specified	None.
Trip coils of non-BES interrupting devices in UFLS or UVLS systems.	No periodic maintenance specified	None.

Table 4-1 Maintenance Activities and Intervals for Automatic Reclosing Components Component Type – Reclosing Relay		
Component Attributes	**Maximum Maintenance Interval**	**Maintenance Activities**
Any unmonitored reclosing relay not having all the monitoring attributes of a category below.	6 Calendar Years	Verify that settings are as specified. For non-microprocessor relays: • Test and, if necessary calibrate For microprocessor relays: • Verify operation of the relay inputs and outputs that are essential to proper functioning of the Automatic Reclosing.
Monitored microprocessor reclosing relay with the following: • Internal self~~-~~diagnosis and alarming (See Table 2). • Alarming for power supply failure (See Table 2).	12 Calendar Years	Verify: • Settings are as specified. • Operation of the relay inputs and outputs that are essential to proper functioning of the Automatic Reclosing.

Table 4-2(a) Maintenance Activities and Intervals for Automatic Reclosing Components Component Type – Control Circuitry Associated with Reclosing Relays that are NOT an Integral Part of an ~~SPS~~RAS		
Component Attributes	**Maximum Maintenance Interval**	**Maintenance Activities**
Unmonitored Control circuitry associated with Automatic Reclosing that is not an integral part of an ~~SPS~~RAS.	12 Calendar Years	Verify that Automatic Reclosing, upon initiation, does not issue a premature closing command to the close circuitry.
Control circuitry associated with Automatic Reclosing that is not part of an ~~SPS~~RAS and is monitored and alarmed for conditions that would result in a premature closing command. (See Table 2)	No periodic maintenance specified	None.

Table 4-2(b) Maintenance Activities and Intervals for Automatic Reclosing Components Component Type – Control Circuitry Associated with Reclosing Relays that ARE an Integral Part of an ~~SPS~~RAS		
Component Attributes	**Maximum Maintenance Interval**	**Maintenance Activities**
Close coils or actuators of circuit breakers or similar devices that are used in conjunction with Automatic Reclosing as part of an ~~SPS~~RAS (regardless of any monitoring of the control circuitry).	6 Calendar Years	Verify that each close coil or actuator is able to operate the circuit breaker or mitigating device.
Unmonitored close control circuitry associated with Automatic Reclosing used as an integral part of an ~~SPS~~RAS.	12 Calendar Years	Verify all paths of the control circuits associated with Automatic Reclosing that are essential for proper operation of the ~~SPS~~RAS.
Control circuitry associated with Automatic Reclosing that is an integral part of an ~~SPS~~RAS whose integrity is monitored and alarmed. (See Table 2)	No periodic maintenance specified	None.

Table 5 Maintenance Activities and Intervals for Sudden Pressure Relaying Note: In cases where Components of Sudden Pressure Relaying are common to Components listed in Table 1-5, the Components only need to be tested once during a distinct maintenance interval.		
Component Attributes	**Maximum Maintenance Interval**	**Maintenance Activities**
Any fault pressure relay.	6 Calendar Years	Verify the pressure or flow sensing mechanism is operable.
Electromechanical lockout devices which are directly in a trip path from the fault pressure relay to the interrupting device trip coil (regardless of any monitoring of the control circuitry).	6 Calendar Years	Verify electrical operation of electromechanical lockout devices.
Unmonitored control circuitry associated with Sudden Pressure Relaying.	12 Calendar Years	Verify all paths of the trip circuits inclusive of all auxiliary relays through the trip coil(s) of the circuit breakers or other interrupting devices.
Control circuitry associated with Sudden Pressure Relaying whose integrity is monitored and alarmed (See Table 2).	No periodic maintenance specified	None.

PRC-005 — Attachment A

Criteria for a Performance-Based Protection System Maintenance Program

Purpose: To establish a technical basis for initial and continued use of a performance-based Protection System Maintenance Program (PSMP).

To establish the technical justification for the initial use of a performance-based PSMP:

1. Develop a list with a description of Components included in each designated Segment, with a minimum Segment population of 60 Components.
2. Maintain the Components in each Segment according to the time-based maximum allowable intervals established in Tables 1-1 through 1-5, Table 3, ~~and~~ Tables 4-1 through 4-2, and Table 5 until results of maintenance activities for the Segment are available for a minimum of 30 individual Components of the Segment.
3. Document the maintenance program activities and results for each Segment, including maintenance dates and Countable Events for each included Component.
4. Analyze the maintenance program activities and results for each Segment to determine the overall performance of the Segment and develop maintenance intervals.
5. Determine the maximum allowable maintenance interval for each Segment such that the Segment experiences Countable Events on no more than 4% of the Components within the Segment, for the greater of either the last 30 Components maintained or all Components maintained in the previous year.

To maintain the technical justification for the ongoing use of a performance-based PSMP:

1. At least annually, update the list of Components and Segments and/or description if any changes occur within the Segment.
2. Perform maintenance on the greater of 5% of the Components (addressed in the performance based PSMP) in each Segment or 3 individual Components within the Segment in each year.
3. For the prior year, analyze the maintenance program activities and results for each Segment to determine the overall performance of the Segment.
4. Using the prior year's data, determine the maximum allowable maintenance interval for each Segment such that the Segment experiences Countable Events on no more than 4% of the Components within the Segment, for the greater of either the last 30 Components maintained or all Components maintained in the previous year.
5. If the Components in a Segment maintained through a performance-based PSMP experience 4% or more Countable Events, develop, document, and implement an action plan to reduce the Countable Events to less than 4% of the Segment population within 3 years.

Implementation Plan

Protection System, Automatic Reclosing, and Sudden Pressure Relaying Maintenance
PRC-005-4

Standards Involved
Approval:

- PRC-005-4 – Protection System, Automatic Reclosing, and Sudden Pressure Relaying Maintenance

Retirement:

- PRC-005-3 – Protection System and Automatic Reclosing Maintenance

Prerequisite Approvals:
N/A

Background:
This implementation plan incorporates and carries forward any aspects of implementation plans for prior versions of PRC-005 where those standards are still in the implementation phase.

The Implementation Plan for PRC-005-4 addresses Sudden Pressure Relaying, Protection Systems as outlined in PRC-005-2, and Automatic Reclosing Components as outlined in PRC-005-3. PRC-005-4 establishes minimum maintenance activities for Sudden Pressure Relaying Component Types and the maximum allowable maintenance intervals for these maintenance activities. PRC-005-4 requires entities to revise the Protection System Maintenance Program by now including Sudden Pressure Relaying Components.

The Implementation Plan reflects consideration of the following:

1. The requirements set forth in the proposed standard, which carry forward requirements from PRC-005-2 and PRC-005-3, establish minimum maintenance activities for Protection System, Automatic Reclosing, and Sudden Pressure Relaying Component Types as well as the maximum allowable maintenance intervals for these maintenance activities. The maintenance activities established may not be presently performed by some entities and the established maximum allowable intervals may be shorter than those currently in use by some entities.

2. For entities not presently performing a maintenance activity or using longer intervals than the maximum allowable intervals established in the proposed standard, it is unrealistic for those entities to be immediately compliant with the new activities or intervals. Further, entities should be allowed to become compliant in such a way as to facilitate a continuing maintenance program.

3. Entities that have previously been performing maintenance within the newly specified intervals may not have all the documentation needed to demonstrate compliance with all of the maintenance activities specified.
4. The Implementation Schedule set forth below in this document carries forward the implementation schedules contained in PRC-005-2 and PRC-005-3 and includes changes needed to address the addition of Sudden Pressure Relaying Components in PRC-005-4.
5. The Implementation Schedule set forth in this document facilitates implementation of the more lengthy maintenance intervals within the revised Protection System Maintenance Program in approximately equally-distributed steps over those intervals prescribed for each respective maintenance activity in order that entities may implement this standard in a systematic method that facilitates an effective ongoing Protection System Maintenance Program.

General Considerations:

Each Transmission Owner, Generator Owner, and Distribution Provider shall maintain documentation to demonstrate compliance with PRC-005-1b, PRC-008-0, PRC-011-0, and PRC-017-0 until that entity meets the requirements of PRC-005-2, or the combined successor standards PRC-005-3 and PRC-005-4, in accordance with this implementation plan.

While entities are transitioning from PRC-005-1b, PRC-008-0, PRC-011-0, PRC-017-0, each entity must be prepared to identify:

- All of its applicable Protection System, Automatic Reclosing, and Sudden Pressure Relaying Components, and
- Whether a Component was last maintained according to PRC-005-1b, PRC-008-0, PRC-011-0, PRC-017-0, or a successor PRC-005 standard.

Effective Date

PRC-005-4 shall become effective on the first day of the first calendar quarter after the date that the standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first calendar quarter after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

Retirement of Existing Standards:

Standards PRC-005-1b, PRC-008-0, PRC-011-0, and PRC-017-0 shall remain active and applicable to an entity's Protection System maintenance activities not yet transitioned to PRC-005-2 or a successor standard during transition. Standards PRC-005-1b, PRC-008-0, PRC-011-0, and PRC-017-0 shall be retired at midnight of the day immediately prior to the first day of the first calendar quarter one hundred fifty-six (156) months following applicable regulatory approval of PRC-005-2 or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities; or, in those

jurisdictions where no regulatory approval is required, at midnight of the day immediately prior to the first day of the first calendar quarter one hundred sixty-eight (168) months following the November 2012 NERC Board of Trustees' adoption of PRC-005-2.

PRC-005-2 shall be retired at midnight of the day immediately prior to the first day of the first calendar quarter, twelve (12) calendar months following applicable regulatory approval of PRC-005-3, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities; or, in those jurisdictions where no regulatory approval is required, the first day of the first calendar quarter twelve (12) calendar months from the date of Board of Trustees' adoption.

PRC-005-3 shall be retired at midnight of the day immediately prior to the first day of the first calendar quarter following applicable regulatory approval of PRC-005-X, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities; or, in those jurisdictions where no regulatory approval is required, the first day of the first calendar quarter from the date of Board of Trustees' adoption.

Implementation Plan for Definitions:

This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the Reliability Standards Glossary of Terms (Glossary) are not repeated here. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, the Glossary definition will be removed from the individual standard and added to the Glossary. The definitions of terms used only in the standard will remain in the standard.

Glossary Definition:

Protection System Maintenance Program (PSMP) — An ongoing program by which Protection System, Automatic Reclosing, and Sudden Pressure Relaying Components are kept in working order and proper operation of malfunctioning Components is restored. A maintenance program for a specific Component includes one or more of the following activities:

- Verify — Determine that the Component is functioning correctly.
- Monitor — Observe the routine in-service operation of the Component.
- Test — Apply signals to a Component to observe functional performance or output behavior, or to diagnose problems.
- Inspect — Examine for signs of Component failure, reduced performance or degradation.
- Calibrate — Adjust the operating threshold or measurement accuracy of a measuring element to meet the intended performance requirement.

Definitions of Terms Used in the Standard:

Sudden Pressure Relaying – A system that trips an interrupting device(s) to isolate the equipment it is monitoring and includes the following Components:

- Fault pressure relay – a mechanical relay or device that detects rapid changes in gas pressure, oil pressure, or oil flow that are indicative of Faults within liquid-filled, wire-wound equipment
- Control circuitry associated with a fault pressure relay

Component Type –

- Any one of the five specific elements of a Protection System.
- Any one of the two specific elements of Automatic Reclosing.
- Any one of the two specific elements of Sudden Pressure Relaying.

Component – Any individual discrete piece of equipment included in a Protection System, Automatic Reclosing, or Sudden Pressure Relaying.

Countable Event – A failure of a Component requiring repair or replacement, any condition discovered during the maintenance activities in Tables 1-1 through 1-5, Table 3, Tables 4-1 through 4-2, and Table 5, which requires corrective action or a Protection System Misoperation attributed to hardware failure or calibration failure. Misoperations due to product design errors, software errors, relay settings different from specified settings, Protection System Component, Automatic Reclosing, or Sudden Pressure Relaying configuration or application errors are not included in Countable Events.

Implementation Plan for New or Revised Definitions:

New and revised definitions (Sudden Pressure Relaying, Protection System Maintenance Program, Component Type, Component, and Countable Event) shall become effective after the date that the definitions are approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a definition to go into effect. Where approval by an applicable governmental authority is not required, the definitions shall become effective on the first day of the first calendar quarter after the date the definitions are adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

Implementation Plan for Requirements R1, R2, and R5:

For Protection System Components, entities shall be 100% compliant on the first day of the first calendar quarter twelve (12) months following applicable regulatory approvals of PRC-005-2 or, in those jurisdictions where no regulatory approval is required, on the first day of the first calendar quarter twenty-four (24) months following the November 2012 NERC Board of Trustees' adoption of PRC-005-2 or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

For Automatic Reclosing Components, entities shall be 100% compliant on the first day of the first calendar quarter twelve (12) months following applicable regulatory approvals of PRC-005-3 or, in those jurisdictions where no regulatory approval is required, on the first day of the first calendar quarter twenty-four (24) months following NERC Board of Trustees' adoption of PRC-005-3 or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

For Sudden Pressure Relaying Components, entities shall be 100% compliant on the first day of the first calendar quarter twelve (12) months following applicable regulatory approvals of PRC-005-4 or, in those jurisdictions where no regulatory approval is required, on the first day of the first calendar quarter twenty-four (24) months following NERC Board of Trustees' adoption of PRC-005-4 or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

Implementation Plan for Requirements R3 and R4:

1. For Protection System Component maintenance activities with maximum allowable intervals of less than one (1) calendar year, as established in Tables 1-1 through 1-5:

    - The entity shall be 100% compliant on the first day of the first calendar quarter eighteen (18) months following applicable regulatory approval of PRC-005-2, or in those jurisdictions where no regulatory approval is required, on the first day of the first calendar quarter thirty (30) months following the November 2012 NERC Board of Trustees' adoption of PRC-005-2 or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

2. For Protection System Component maintenance activities with maximum allowable intervals one (1) calendar year or more, but two (2) calendar years or less, as established in Tables 1-1 through 1-5:

    - The entity shall be 100% compliant on the first day of the first calendar quarter thirty-six (36) months following applicable regulatory approval of PRC-005-2 or, in those jurisdictions where no regulatory approval is required, on the first day of the first calendar quarter forty-eight (48) months following the November 2012 NERC Board of Trustees' adoption of PRC-005-2 or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

3. For Protection System Component maintenance activities with maximum allowable intervals of three (3) calendar years, as established in Tables 1-1 through 1-5:

    - The entity shall be at least 30% compliant on the first day of the first calendar quarter twenty-four (24) months following applicable regulatory approval of PRC-005-2 (or, for generating plants with scheduled outage intervals exceeding two years, at the conclusion of the first succeeding maintenance outage) or, in those jurisdictions where no regulatory approval is required, on the first day of the first calendar quarter thirty-six (36) months following the November 2012 NERC Board of Trustees' adoption of PRC-005-2 or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

- The entity shall be at least 60% compliant on the first day of the first calendar quarter thirty-six (36) months following applicable regulatory approval of PRC-005-2 or, in those jurisdictions where no regulatory approval is required, on the first day of the first calendar quarter forty-eight (48) months following NERC Board of Trustees' adoption of PRC-005-2 or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.
- The entity shall be 100% compliant on the first day of the first calendar quarter forty-eight (48) months following applicable regulatory approval of PRC-005-2 or, in those jurisdictions where no regulatory approval is required, on the first day of the first calendar quarter sixty (60) months following the November 2012 NERC Board of Trustees' adoption of PRC-005-2 or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

4. For Protection System Component maintenance activities with maximum allowable intervals of six (6) calendar years, as established in Tables 1-1 through 1-5 and Table 3:
   - The entity shall be at least 30% compliant on the first day of the first calendar quarter thirty-six (36) months following applicable regulatory approval of PRC-005-2 (or, for generating plants with scheduled outage intervals exceeding three years, at the conclusion of the first succeeding maintenance outage) or, in those jurisdictions where no regulatory approval is required, on the first day of the first calendar quarter forty-eight (48) months following the November 2012 NERC Board of Trustees' adoption of PRC-005-2 or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.
   - The entity shall be at least 60% compliant on the first day of the first calendar quarter sixty (60) months following applicable regulatory approval of PRC-005-2 or, in those jurisdictions where no regulatory approval is required, on the first day of the first calendar quarter seventy-two (72) months following the November 2012 NERC Board of Trustees' adoption of PRC-005-2 or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.
   - The entity shall be 100% compliant on the first day of the first calendar quarter eighty-four (84) months following applicable regulatory approval of PRC-005-2 or, in those jurisdictions where no regulatory approval is required, on the first day of the first calendar quarter ninety-six (96) months following the November 2012 NERC Board of Trustees' adoption of PRC-005-2 or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.
5. For Automatic Reclosing Component maintenance activities with maximum allowable intervals of six (6) calendar years, as established in Table 4-1, 4-2(a) and 4-2(b):
   - The entity shall be at least 30% compliant on the first day of the first calendar quarter thirty-six (36) months following applicable regulatory approval of PRC-005-3 (or, for generating plants with scheduled outage intervals exceeding three years, at the conclusion of the first succeeding maintenance outage) or, in those jurisdictions where no regulatory approval is required, on the

first day of the first calendar quarter forty-eight (48) months following NERC Board of Trustees' adoption of PRC-005-3 or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

- The entity shall be at least 60% compliant on the first day of the first calendar quarter sixty (60) months following applicable regulatory approval of PRC-005-3 or, in those jurisdictions where no regulatory approval is required, on the first day of the first calendar quarter seventy-two (72) months following NERC Board of Trustees' adoption of PRC-005-3, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.
- The entity shall be 100% compliant on the first day of the first calendar quarter eighty-four (84) months following applicable regulatory approval of PRC-005-3 or, in those jurisdictions where no regulatory approval is required, on the first day of the first calendar quarter ninety-six (96) months following NERC Board of Trustees' adoption of PRC-005-3 or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

6. For Sudden Pressure Relaying Component maintenance activities with maximum allowable intervals of six (6) calendar years, as established in Table 5:

- The entity shall be at least 30% compliant on the first day of the first calendar quarter thirty-six (36) months following applicable regulatory approval of PRC-005-4 (or, for generating plants with scheduled outage intervals exceeding three years, at the conclusion of the first succeeding maintenance outage) or, in those jurisdictions where no regulatory approval is required, on the first day of the first calendar quarter forty-eight (48) months following NERC Board of Trustees' adoption of PRC-005-X or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.
- The entity shall be at least 60% compliant on the first day of the first calendar quarter sixty (60) months following applicable regulatory approval of PRC-005-4 or, in those jurisdictions where no regulatory approval is required, on the first day of the first calendar quarter seventy-two (72) months following NERC Board of Trustees' adoption of PRC-005-4, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.
- The entity shall be 100% compliant on the first day of the first calendar quarter eighty-four (84) months following applicable regulatory approval of PRC-005-4 or, in those jurisdictions where no regulatory approval is required, on the first day of the first calendar quarter ninety-six (96) months following NERC Board of Trustees' adoption of PRC-005-4 or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

7. For Protection System Component maintenance activities with maximum allowable intervals of twelve (12) calendar years, as established in Tables 1-1 through 1-5, Table 2, and Table 3:

- The entity shall be at least 30% compliant on the first day of the first calendar quarter sixty (60) months following applicable regulatory approval of PRC-005-2 or, in those jurisdictions where no regulatory approval is required, on the first day of the first calendar quarter seventy-two

(72) months following the November 2012 NERC Board of Trustees' adoption of PRC-005-2 or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

- The entity shall be at least 60% compliant on the first day of the first calendar quarter following one hundred eight (108) months following applicable regulatory approval of PRC-005-2 or, in those jurisdictions where no regulatory approval is required, on the first day of the first calendar quarter one hundred twenty (120) months following the November 2012 NERC Board of Trustees' adoption of PRC-005-2 or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.
- The entity shall be 100% compliant on the first day of the first calendar quarter one hundred fifty-six (156) months following applicable regulatory approval of PRC-005-2 or, in those jurisdictions where no regulatory approval is required, on the first day of the first calendar quarter one hundred sixty-eight (168) months following the November 2012 NERC Board of Trustees' adoption of PRC-005-2 or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

8. For Automatic Reclosing Component maintenance activities with maximum allowable intervals of twelve (12) calendar years, as established in Table 4-1, 4-2(a) and 4-2(b):

- The entity shall be at least 30% compliant on the first day of the first calendar quarter sixty (60) months following applicable regulatory approval of PRC-005-3 or, in those jurisdictions where no regulatory approval is required, on the first day of the first calendar quarter seventy-two (72) months following NERC Board of Trustees' adoption of PRC-005-3 or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.
- The entity shall be at least 60% compliant on the first day of the first calendar quarter following one hundred eight (108) months following applicable regulatory approval of PRC-005-3 or, in those jurisdictions where no regulatory approval is required, on the first day of the first calendar quarter one hundred twenty (120) months following NERC Board of Trustees' adoption of PRC-005-3 or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.
- The entity shall be 100% compliant on the first day of the first calendar quarter one hundred fifty-six (156) months following applicable regulatory approval of PRC-005-3 or, in those jurisdictions where no regulatory approval is required, on the first day of the first calendar quarter one hundred sixty-eight (168) months following NERC Board of Trustees' adoption of PRC-005-3 or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

9. For Sudden Pressure Relaying Component maintenance activities with maximum allowable intervals of twelve (12) calendar years, as established in Table 5:

- The entity shall be at least 30% compliant on the first day of the first calendar quarter sixty (60) months following applicable regulatory approval of PRC-005-4 or, in those jurisdictions where no regulatory approval is required, on the first day of the first calendar quarter seventy-two (72) months following NERC Board of Trustees' adoption of PRC-005-4 or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.
- The entity shall be at least 60% compliant on the first day of the first calendar quarter following one hundred eight (108) months following applicable regulatory approval of PRC-005-4 or, in those jurisdictions where no regulatory approval is required, on the first day of the first calendar quarter one hundred twenty (120) months following NERC Board of Trustees' adoption of PRC-005-4 or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.
- The entity shall be 100% compliant on the first day of the first calendar quarter one hundred fifty-six (156) months following applicable regulatory approval of PRC-005-4 or, in those jurisdictions where no regulatory approval is required, on the first day of the first calendar quarter one hundred sixty-eight (168) months following NERC Board of Trustees' adoption of PRC-005-4 or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

Applicability:

This standard applies to the following functional entities:

- Transmission Owner
- Generator Owner
- Distribution Provider

Implementation Plan

Protection System, Automatic Reclosing, and Sudden Pressure Relaying Maintenance

PRC-005-4~~X~~

Standards Involved

Approval:

- PRC-005-4~~X~~ – Protection System, Automatic Reclosing, and Sudden Pressure Relaying Maintenance

Retirement:

- PRC-005-3 – Protection System and Automatic Reclosing Maintenance

Prerequisite Approvals:

N/A

Background:

This implementation plan incorporates and carries forward any aspects of implementation plans for prior versions of PRC-005 where those standards are still in the implementation phase.

The Implementation Plan for PRC-005-4~~X~~ addresses Sudden Pressure Relaying, Protection Systems as outlined in PRC-005-2, and Automatic Reclosing Components as outlined in PRC-005-3. PRC-005-4~~X~~ establishes minimum maintenance activities for Sudden Pressure Relaying Component Types and the maximum allowable maintenance intervals for these maintenance activities. PRC-005-4~~X~~ requires entities to revise the Protection System Maintenance Program by now including Sudden Pressure Relaying Components.

The Implementation Plan reflects consideration of the following:

1. The requirements set forth in the proposed standard, which carry forward requirements from PRC-005-2 and PRC-005-3, establish minimum maintenance activities for Protection System, Automatic Reclosing, and Sudden Pressure Relaying Component Types as well as the maximum allowable maintenance intervals for these maintenance activities. The maintenance activities established may not be presently performed by some entities and the established maximum allowable intervals may be shorter than those currently in use by some entities.
2. For entities not presently performing a maintenance activity or using longer intervals than the maximum allowable intervals established in the proposed standard, it is unrealistic for those entities to be immediately compliant with the new activities or intervals. Further, entities should be allowed to become compliant in such a way as to facilitate a continuing maintenance program.

3. Entities that have previously been performing maintenance within the newly specified intervals may not have all the documentation needed to demonstrate compliance with all of the maintenance activities specified.
4. The Implementation Schedule set forth below in this document carries forward the implementation schedules contained in PRC-005-2 and PRC-005-3 and includes changes needed to address the addition of Sudden Pressure Relaying Components in PRC-005-4~~X~~.
5. The Implementation Schedule set forth in this document facilitates implementation of the more lengthy maintenance intervals within the revised Protection System Maintenance Program in approximately equally-distributed steps over those intervals prescribed for each respective maintenance activity in order that entities may implement this standard in a systematic method that facilitates an effective ongoing Protection System Maintenance Program.

General Considerations:

Each Transmission Owner, Generator Owner, and Distribution Provider shall maintain documentation to demonstrate compliance with PRC-005-1b, PRC-008-0, PRC-011-0, and PRC-017-0 until that entity meets the requirements of PRC-005-2, or the combined successor standards PRC-005-3 and PRC-005-4~~X~~, in accordance with this implementation plan.

While entities are transitioning from PRC-005-1b, PRC-008-0, PRC-011-0, PRC-017-0, each entity must be prepared to identify:

- All of its applicable Protection System, Automatic Reclosing, and Sudden Pressure Relaying Components, and
- Whether a Component was last maintained according to PRC-005-1b, PRC-008-0, PRC-011-0, PRC-017-0, or a successor PRC-005 standard.

Effective Date

PRC-005-4~~X~~ shall become effective on the first day of the first calendar quarter after the date that the standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first calendar quarter after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

Retirement of Existing Standards:

Standards PRC-005-1b, PRC-008-0, PRC-011-0, and PRC-017-0 shall remain active and applicable to an entity's Protection System maintenance activities not yet transitioned to PRC-005-2 or a successor standard during transition. Standards PRC-005-1b, PRC-008-0, PRC-011-0, and PRC-017-0 shall be retired at midnight of the day immediately prior to the first day of the first calendar quarter one hundred fifty-six (156) months following applicable regulatory approval of PRC-005-2 or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities; or, in those

jurisdictions where no regulatory approval is required, at midnight of the day immediately prior to the first day of the first calendar quarter one hundred sixty-eight (168) months following the November 2012 NERC Board of Trustees' adoption of PRC-005-2.

PRC-005-2 shall be retired at midnight of the day immediately prior to the first day of the first calendar quarter, twelve (12) calendar months following applicable regulatory approval of PRC-005-3, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities; or, in those jurisdictions where no regulatory approval is required, the first day of the first calendar quarter twelve (12) calendar months from the date of Board of Trustees' adoption.

PRC-005-3 shall be retired at midnight of the day immediately prior to the first day of the first calendar quarter following applicable regulatory approval of PRC-005-X, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities; or, in those jurisdictions where no regulatory approval is required, the first day of the first calendar quarter from the date of Board of Trustees' adoption.

Implementation Plan for Definitions:

This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the Reliability Standards Glossary of Terms (Glossary) are not repeated here. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, the Glossary definition will be removed from the individual standard and added to the Glossary. The definitions of terms used only in the standard will remain in the standard.

Glossary Definition:

Protection System Maintenance Program (PSMP) — An ongoing program by which Protection System, Automatic Reclosing, and Sudden Pressure Relaying Components are kept in working order and proper operation of malfunctioning Components is restored. A maintenance program for a specific Component includes one or more of the following activities:

- Verify — Determine that the Component is functioning correctly.
- Monitor — Observe the routine in-service operation of the Component.
- Test — Apply signals to a Component to observe functional performance or output behavior, or to diagnose problems.
- Inspect — Examine for signs of Component failure, reduced performance or degradation.
- Calibrate — Adjust the operating threshold or measurement accuracy of a measuring element to meet the intended performance requirement.

Definitions of Terms Used in the Standard:

Sudden Pressure Relaying – A system that trips an interrupting device(s) to isolate the equipment it is monitoring and includes the following Components:

- Fault pressure relay – a mechanical relay or device that detects rapid changes in gas pressure, oil pressure, or oil flow that are indicative of Faults within liquid-filled, wire-wound equipment
- Control circuitry associated with a fault pressure relay

Component Type –

- Any one of the five specific elements of a Protection System.
- Any one of the two specific elements of Automatic Reclosing.
- Any one of the two specific elements of Sudden Pressure Relaying.

Component – Any individual discrete piece of equipment included in a Protection System, Automatic Reclosing, or Sudden Pressure Relaying.

Countable Event – A failure of a Component requiring repair or replacement, any condition discovered during the maintenance activities in Tables 1-1 through 1-5, Table 3, Tables 4-1 through 4-2, and Table 5, which requires corrective action or a Protection System Misoperation attributed to hardware failure or calibration failure. Misoperations due to product design errors, software errors, relay settings different from specified settings, Protection System Component, Automatic Reclosing, or Sudden Pressure Relaying configuration or application errors are not included in Countable Events.

Implementation Plan for New or Revised Definitions:

New and revised definitions (Sudden Pressure Relaying, Protection System Maintenance Program, Component Type, Component, and Countable Event) shall become effective after the date that the definitions are approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a definition to go into effect. Where approval by an applicable governmental authority is not required, the definitions shall become effective on the first day of the first calendar quarter after the date the definitions are adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

Implementation Plan for Requirements R1, R2, and R5:

For Protection System Components, entities shall be 100% compliant on the first day of the first calendar quarter twelve (12) months following applicable regulatory approvals of PRC-005-2 or, in those jurisdictions where no regulatory approval is required, on the first day of the first calendar quarter twenty-four (24) months following the November 2012 NERC Board of Trustees' adoption of PRC-005-2 or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

For Automatic Reclosing Components, entities shall be 100% compliant on the first day of the first calendar quarter twelve (12) months following applicable regulatory approvals of PRC-005-3 or, in those jurisdictions where no regulatory approval is required, on the first day of the first calendar quarter twenty-four (24) months following NERC Board of Trustees' adoption of PRC-005-3 or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

For Sudden Pressure Relaying Components, entities shall be 100% compliant on the first day of the first calendar quarter twelve (12) months following applicable regulatory approvals of PRC-005-4~~X~~ or, in those jurisdictions where no regulatory approval is required, on the first day of the first calendar quarter twenty-four (24) months following NERC Board of Trustees' adoption of PRC-005-4~~X~~ or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

Implementation Plan for Requirements R3 and R4:

1. For Protection System Component maintenance activities with maximum allowable intervals of less than one (1) calendar year, as established in Tables 1-1 through 1-5:
    - The entity shall be 100% compliant on the first day of the first calendar quarter eighteen (18) months following applicable regulatory approval of PRC-005-2, or in those jurisdictions where no regulatory approval is required, on the first day of the first calendar quarter thirty (30) months following the November 2012 NERC Board of Trustees' adoption of PRC-005-2 or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.
2. For Protection System Component maintenance activities with maximum allowable intervals one (1) calendar year or more, but two (2) calendar years or less, as established in Tables 1-1 through 1-5:
    - The entity shall be 100% compliant on the first day of the first calendar quarter thirty-six (36) months following applicable regulatory approval of PRC-005-2 or, in those jurisdictions where no regulatory approval is required, on the first day of the first calendar quarter forty-eight (48) months following the November 2012 NERC Board of Trustees' adoption of PRC-005-2 or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.
3. For Protection System Component maintenance activities with maximum allowable intervals of three (3) calendar years, as established in Tables 1-1 through 1-5:
    - The entity shall be at least 30% compliant on the first day of the first calendar quarter twenty-four (24) months following applicable regulatory approval of PRC-005-2 (or, for generating plants with scheduled outage intervals exceeding two years, at the conclusion of the first succeeding maintenance outage) or, in those jurisdictions where no regulatory approval is required, on the first day of the first calendar quarter thirty-six (36) months following the November 2012 NERC Board of Trustees' adoption of PRC-005-2 or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

- The entity shall be at least 60% compliant on the first day of the first calendar quarter thirty-six (36) months following applicable regulatory approval of PRC-005-2 or, in those jurisdictions where no regulatory approval is required, on the first day of the first calendar quarter forty-eight (48) months following NERC Board of Trustees' adoption of PRC-005-2 or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.
- The entity shall be 100% compliant on the first day of the first calendar quarter forty-eight (48) months following applicable regulatory approval of PRC-005-2 or, in those jurisdictions where no regulatory approval is required, on the first day of the first calendar quarter sixty (60) months following the November 2012 NERC Board of Trustees' adoption of PRC-005-2 or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

4. For Protection System Component maintenance activities with maximum allowable intervals of six (6) calendar years, as established in Tables 1-1 through 1-5 and Table 3:

   - The entity shall be at least 30% compliant on the first day of the first calendar quarter thirty-six (36) months following applicable regulatory approval of PRC-005-2 (or, for generating plants with scheduled outage intervals exceeding three years, at the conclusion of the first succeeding maintenance outage) or, in those jurisdictions where no regulatory approval is required, on the first day of the first calendar quarter forty-eight (48) months following the November 2012 NERC Board of Trustees' adoption of PRC-005-2 or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.
   - The entity shall be at least 60% compliant on the first day of the first calendar quarter sixty (60) months following applicable regulatory approval of PRC-005-2 or, in those jurisdictions where no regulatory approval is required, on the first day of the first calendar quarter seventy-two (72) months following the November 2012 NERC Board of Trustees' adoption of PRC-005-2 or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.
   - The entity shall be 100% compliant on the first day of the first calendar quarter eighty-four (84) months following applicable regulatory approval of PRC-005-2 or, in those jurisdictions where no regulatory approval is required, on the first day of the first calendar quarter ninety-six (96) months following the November 2012 NERC Board of Trustees' adoption of PRC-005-2 or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

5. For Automatic Reclosing Component maintenance activities with maximum allowable intervals of six (6) calendar years, as established in Table 4-1, 4-2(a) and 4-2(b):

   - The entity shall be at least 30% compliant on the first day of the first calendar quarter thirty-six (36) months following applicable regulatory approval of PRC-005-3 (or, for generating plants with scheduled outage intervals exceeding three years, at the conclusion of the first succeeding maintenance outage) or, in those jurisdictions where no regulatory approval is required, on the

first day of the first calendar quarter forty-eight (48) months following NERC Board of Trustees' adoption of PRC-005-3 or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

- The entity shall be at least 60% compliant on the first day of the first calendar quarter sixty (60) months following applicable regulatory approval of PRC-005-3 or, in those jurisdictions where no regulatory approval is required, on the first day of the first calendar quarter seventy-two (72) months following NERC Board of Trustees' adoption of PRC-005-3, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.
- The entity shall be 100% compliant on the first day of the first calendar quarter eighty-four (84) months following applicable regulatory approval of PRC-005-3 or, in those jurisdictions where no regulatory approval is required, on the first day of the first calendar quarter ninety-six (96) months following NERC Board of Trustees' adoption of PRC-005-3 or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

6. For Sudden Pressure Relaying Component maintenance activities with maximum allowable intervals of six (6) calendar years, as established in Table 5:

- The entity shall be at least 30% compliant on the first day of the first calendar quarter thirty-six (36) months following applicable regulatory approval of PRC-005-4~~X~~ (or, for generating plants with scheduled outage intervals exceeding three years, at the conclusion of the first succeeding maintenance outage) or, in those jurisdictions where no regulatory approval is required, on the first day of the first calendar quarter forty-eight (48) months following NERC Board of Trustees' adoption of PRC-005-X or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.
- The entity shall be at least 60% compliant on the first day of the first calendar quarter sixty (60) months following applicable regulatory approval of PRC-005-4~~X~~ or, in those jurisdictions where no regulatory approval is required, on the first day of the first calendar quarter seventy-two (72) months following NERC Board of Trustees' adoption of PRC-005-4~~X~~, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.
- The entity shall be 100% compliant on the first day of the first calendar quarter eighty-four (84) months following applicable regulatory approval of PRC-005-4~~X~~ or, in those jurisdictions where no regulatory approval is required, on the first day of the first calendar quarter ninety-six (96) months following NERC Board of Trustees' adoption of PRC-005-4~~X~~ or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

7. For Protection System Component maintenance activities with maximum allowable intervals of twelve (12) calendar years, as established in Tables 1-1 through 1-5, Table 2, and Table 3:

- The entity shall be at least 30% compliant on the first day of the first calendar quarter sixty (60) months following applicable regulatory approval of PRC-005-2 or, in those jurisdictions where no regulatory approval is required, on the first day of the first calendar quarter seventy-two

(72) months following the November 2012 NERC Board of Trustees' adoption of PRC-005-2 or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

- The entity shall be at least 60% compliant on the first day of the first calendar quarter following one hundred eight (108) months following applicable regulatory approval of PRC-005-2 or, in those jurisdictions where no regulatory approval is required, on the first day of the first calendar quarter one hundred twenty (120) months following the November 2012 NERC Board of Trustees' adoption of PRC-005-2 or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.
- The entity shall be 100% compliant on the first day of the first calendar quarter one hundred fifty-six (156) months following applicable regulatory approval of PRC-005-2 or, in those jurisdictions where no regulatory approval is required, on the first day of the first calendar quarter one hundred sixty-eight (168) months following the November 2012 NERC Board of Trustees' adoption of PRC-005-2 or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

8. For Automatic Reclosing Component maintenance activities with maximum allowable intervals of twelve (12) calendar years, as established in Table 4-1, 4-2(a) and 4-2(b):

- The entity shall be at least 30% compliant on the first day of the first calendar quarter sixty (60) months following applicable regulatory approval of PRC-005-3 or, in those jurisdictions where no regulatory approval is required, on the first day of the first calendar quarter seventy-two (72) months following NERC Board of Trustees' adoption of PRC-005-3 or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.
- The entity shall be at least 60% compliant on the first day of the first calendar quarter following one hundred eight (108) months following applicable regulatory approval of PRC-005-3 or, in those jurisdictions where no regulatory approval is required, on the first day of the first calendar quarter one hundred twenty (120) months following NERC Board of Trustees' adoption of PRC-005-3 or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.
- The entity shall be 100% compliant on the first day of the first calendar quarter one hundred fifty-six (156) months following applicable regulatory approval of PRC-005-3 or, in those jurisdictions where no regulatory approval is required, on the first day of the first calendar quarter one hundred sixty-eight (168) months following NERC Board of Trustees' adoption of PRC-005-3 or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

9. For Sudden Pressure Relaying Component maintenance activities with maximum allowable intervals of twelve (12) calendar years, as established in Table 5:

- The entity shall be at least 30% compliant on the first day of the first calendar quarter sixty (60) months following applicable regulatory approval of PRC-005-4~~X~~ or, in those jurisdictions where no regulatory approval is required, on the first day of the first calendar quarter seventy-two (72) months following NERC Board of Trustees' adoption of PRC-005-4~~X~~ or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.
- The entity shall be at least 60% compliant on the first day of the first calendar quarter following one hundred eight (108) months following applicable regulatory approval of PRC-005-4~~X~~ or, in those jurisdictions where no regulatory approval is required, on the first day of the first calendar quarter one hundred twenty (120) months following NERC Board of Trustees' adoption of PRC-005-4~~X~~ or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.
- The entity shall be 100% compliant on the first day of the first calendar quarter one hundred fifty-six (156) months following applicable regulatory approval of PRC-005-4~~X~~ or, in those jurisdictions where no regulatory approval is required, on the first day of the first calendar quarter one hundred sixty-eight (168) months following NERC Board of Trustees' adoption of PRC-005-4~~X~~ or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

Applicability:

This standard applies to the following functional entities:

- Transmission Owner
- Generator Owner
- Distribution Provider

NERC

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Supplementary Reference and FAQ

PRC-005-4 Protection System Maintenance and Testing

October 2014

RELIABILITY | ACCOUNTABILITY




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1. Introduction and Summary

Note: This supplementary reference for PRC-005-4 is neither mandatory nor enforceable.

NERC currently has four Reliability Standards that are mandatory and enforceable in the United States and Canada and address various aspects of maintenance and testing of Protection and Control Systems.

These standards are:

PRC-005-1b — Transmission and Generation Protection System Maintenance and Testing

PRC-008-0 — Underfrequency Load Shedding Equipment Maintenance Programs

PRC-011-0 — UVLS System Maintenance and Testing

PRC-017-0 — Special Protection System Maintenance and Testing

While these standards require that applicable entities have a maintenance program for Protection Systems, and that these entities must be able to demonstrate they are carrying out such a program, there are no specifics regarding the technical requirements for Protection System maintenance programs. Furthermore, FERC Order 693 directed additional modifications respective to Protection System maintenance programs. PRC-005-3 will replace PRC-005-2 which combined and replaced PRC-005, PRC-008, PRC-011 and PRC-017. PRC-005-3 adds Automatic Reclosing to PRC-005-2. PRC-005-2 addressed these directed modifications and replaces PRC-005, PRC-008, PRC-011 and PRC-017.

FERC Order 758 further directed that maintenance of reclosing relays and sudden pressure relays that affect the reliable operation of the Bulk Power System be addressed. PRC-005-3 addresses this directive regarding reclosing relays, and, when approved, will supersede PRC-005-2. PRC-005-4 addresses this directive regarding sudden pressure relays and, when approved, will supersede PRC-005-3.

This document augments the Supplementary Reference and FAQ previously developed for PRC-005-2 by including discussion relevant to Automatic Reclosing added in PRC-005-3 and Sudden Pressure Relaying in PRC-005-4.

2. Need for Verifying Protection System Performance

Protective relays have been described as silent sentinels, and do not generally demonstrate their performance until a Fault or other power system problem requires that they operate to protect power system Elements, or even the entire Bulk Electric System (BES). Lacking Faults, switching operations or system problems, the Protection Systems may not operate, beyond static operation, for extended periods. A Misoperation - a false operation of a Protection System or a failure of the Protection System to operate, as designed, when needed - can result in equipment damage, personnel hazards, and wide-area Disturbances or unnecessary customer outages. Maintenance or testing programs are used to determine the performance and availability of Protection Systems.

Typically, utilities have tested Protection Systems at fixed time intervals, unless they had some incidental evidence that a particular Protection System was not behaving as expected. Testing practices vary widely across the industry. Testing has included system functionality, calibration of measuring devices, and correctness of settings. Typically, a Protection System must be visited at its installation site and, in many cases, removed from service for this testing.

Fundamentally, a Reliability Standard for Protection System Maintenance and Testing requires the performance of the maintenance activities that are necessary to detect and correct plausible age and service related degradation of the Protection System components, such that a properly built and commissioned Protection System will continue to function as designed over its service life.

Similarly station batteries, which are an important part of the station dc supply, are not called upon to provide instantaneous dc power to the Protection System until power is required by the Protection System to operate circuit breakers or interrupting devices to clear Faults or to isolate equipment.

2.1 Existing NERC Standards for Protection System Maintenance and Testing

For critical BES protection functions, NERC standards have required that each utility or asset owner define a testing program. The starting point is the existing Standard PRC-005, briefly restated as follows:

Purpose: To document and implement programs for the maintenance of all Protection Systems affecting the reliability of the Bulk Electric System (BES) so that these Protection Systems are kept in working order.

PRC-005-4 is not specific on where the boundaries of the Protection Systems lie. However, the definition of Protection System in the NERC Glossary of Terms used in Reliability Standards indicates what must be included as a minimum.

At the beginning of the project to develop PRC-005-2, the definition of Protection System was:

Protective relays, associated communications Systems, voltage and current sensing devices, station batteries and dc control circuitry.

Applicability: Owners of generation and transmission Protection Systems.

Requirements: The owner shall have a documented maintenance program with test intervals. The owner must keep records showing that the maintenance was performed at the specified intervals.

2.2 Protection System Definition

The most recently approved definition of Protection Systems is:

- Protective relays which respond to electrical quantities,
- Communications systems necessary for correct operation of protective functions,
- Voltage and current sensing devices providing inputs to protective relays,
- Station dc supply associated with protective functions (including station batteries, battery chargers, and non-battery-based dc supply), and
- Control circuitry associated with protective functions through the trip coil(s) of the circuit breakers or other interrupting devices.

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:

"*…that are installed for the purpose of detecting Faults on BES Elements (lines, buses, transformers, etc.).*"

The drafting team intends that this standard will follow with any definition of the Bulk Electric System. There should be no ambiguity; if the Element is a BES Element, then the Protection System protecting that Element should then be included within this standard. If there is regional variation to the definition, then there will be a corresponding regional variation to the Protection Systems that fall under this standard.

There is no way for the Standard Drafting Team to know whether a specific 230KV line, 115KV line (even 69KV line), for example, should be included or excluded. Therefore, the team set the clear intent that the standard language should simply be applicable to Protection Systems for BES Elements.

The BES is a NERC defined term that, from time to time, may undergo revisions. Additionally, there may even be regional variations that are allowed in the present and future definitions. See the NERC Glossary of Terms for the present, in-force definition. See the applicable Regional Reliability Organization for any applicable allowed variations.

While this standard will undergo revisions in the future, this standard will not attempt to keep up with revisions to the NERC definition of BES, but, rather, simply make BES Protection Systems applicable.

The Standard is applied to Generator Owners (GO) and Transmission Owners (TO) because GOs and TOs have equipment that is BES equipment. The standard brings in Distribution Providers (DP) because, depending on the station configuration of a particular substation, there may be

Protection System equipment installed at a non-transmission voltage level (Distribution Provider equipment) that is wholly or partially installed to protect the BES. PRC-005-4 would apply to this equipment. An example is underfrequency load-shedding, which is frequently applied well down into the distribution system to meet PRC-007-0.

PRC-005-2 replaced the existing PRC-005, PRC-008, PRC-011 and PRC-017. Much of the original intent of those standards was carried forward whenever it was possible to continue the intent without a disagreement with FERC Order 693. For example, the original PRC-008 was constructed quite differently than the original PRC-005. The drafting team agrees with the intent of this and notes that distributed tripping schemes would have to exhibit multiple failures to trip before they would prove to be significant, as opposed to a single failure to trip of, for example, a transmission Protection System Bus Differential lock-out relay. While many failures of these distribution breakers could add up to be significant, it is also believed that distribution breakers are operated often on just Fault clearing duty; and, therefore, the distribution circuit breakers are operated at least as frequently as stipulated in any requirement in this standard.

Additionally, since PRC-005-2 replaced PRC-011, it will be important to make the distinction between under-voltage Protection Systems that protect individual Loads and Protection Systems that are UVLS schemes that protect the BES. Any UVLS scheme that had been applicable under PRC-011 is now applicable under PRC-005-2. An example of an under-voltage load-shedding scheme that is not applicable to this standard is one in which the tripping action was intended to prevent low distribution voltage to a specific Load from a Transmission system that was intact except for the line that was out of service, as opposed to preventing a Cascading outage or Transmission system collapse.

It had been correctly noted that the devices needed for PRC-011 are the very same types of devices needed in PRC-005.

Thus, a standard written for Protection Systems of the BES can easily make the needed requirements for Protection Systems, and replace some other standards at the same time.

2.3.1 Frequently Asked Questions:

What exactly is the BES, or Bulk Electric System?

BES is the abbreviation for Bulk Electric System. BES is a term in the Glossary of Terms used in Reliability Standards, and is not being modified within this draft standard.

Why is Distribution Provider included within the Applicable Entities and as a responsible entity within several of the requirements? Wouldn't anyone having relevant Facilities be a Transmission Owner?

Depending on the station configuration of a particular substation, there may be Protection System equipment installed at a non-transmission voltage level (Distribution Provider equipment) that is wholly or partially installed to protect the BES. PRC-005-4 applies to this equipment. An example is underfrequency load-shedding, which is frequently applied well down into the distribution system to meet PRC-007-0.

We have an under voltage load-shedding (UVLS) system in place that prevents one of our distribution substations from supplying extremely low voltage in the case of a specific transmission line outage. The transmission line is part of the BES. Does this mean that our UVLS system falls within this standard?

The situation, as stated, indicates that the tripping action was intended to prevent low distribution voltage to a specific Load from a Transmission System that was intact, except for the line that was out of service, as opposed to preventing Cascading outage or Transmission System Collapse.

This standard is not applicable to this UVLS.

We have a UFLS or UVLS scheme that sheds the necessary Load through distribution-side circuit breakers and circuit reclosers. Do the trip-test requirements for circuit breakers apply to our situation?

No. Distributed tripping schemes would have to exhibit multiple failures to trip before they would prove to be significant, as opposed to a single failure to trip of, for example, a transmission Protection System bus differential lock-out relay. While many failures of these distribution breakers could add up to be significant, it is also believed that distribution breakers are operated often on just Fault clearing duty; and, therefore, the distribution circuit breakers are operated at least as frequently as any requirements that might have appeared in this standard.

We have a UFLS scheme that, in some locales, sheds the necessary Load through non-BES circuit breakers and, occasionally, even circuit switchers. Do the trip-test requirements for circuit breakers apply to our situation?

If your "non-BES circuit breaker" has been brought into this standard by the inclusion of UFLS requirements, and otherwise would not have been brought into this standard, then the answer is that there are no trip-test requirements. For these devices that are otherwise non-BES assets, these tripping schemes would have to exhibit multiple failures to trip before they would prove to be as significant as, for example, a single failure to trip of a transmission Protection System bus differential lock-out relay.

How does the "Facilities" section of "Applicability" track with the standards that will be retired once PRC-005-2 becomes effective?

In establishing PRC-005-2, the drafting team combined legacy standards PRC-005-1b, PRC-008-0, PRC-011-0, and PRC-017-0. The merger of the subject matter of these standards is reflected in Applicability 4.2.

The intent of the drafting team is that the legacy standards be reflected in PRC-005-2 as follows:

- Applicability of PRC-005-1b for Protection Systems relating to non-generator elements of the BES is addressed in 4.2.1;
- Applicability of PRC-008-0 for underfrequency load shedding systems is addressed in 4.2.2;
- Applicability of PRC-011-0 for undervoltage load shedding relays is addressed in 4.2.3;
- Applicability of PRC-017-0 for Remedial Action Schemes is addressed in 4.2.4;
- Applicability of PRC-005-1b for Protection Systems for BES generators is addressed in 4.2.5.

2.4 Applicable Relays

The NERC Glossary definition has a Protection System including relays, dc supply, current and voltage sensing devices, dc control circuitry and associated communications circuits. The relays to which this standard applies are those protective relays that respond to electrical quantities and provide a trip output to trip coils, dc control circuitry or associated communications equipment. This definition extends to IEEE Device No. 86 (lockout relay) and IEEE Device No. 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.

Relays that respond to non-electrical inputs or impulses (such as, but not limited to, vibration, seismic, thermal or gas accumulation) are not included.

Automatic Reclosing is addressed in PRC-005-3 by explicitly addressing them outside the definition of Protection System. The specific locations for applicable Automatic Reclosing are addressed in Applicability Section 4.2.6.

Sudden Pressure Relaying is addressed in PRC-005-4 by explicitly addressing them outside the definition of Protection System. The specific locations for applicable Sudden Pressure Relaying are addressed in Applicability Section 4.2.1, 4.2.5.2, 4.2.5.3 and 4.2.5.4.

2.4.1 Frequently Asked Questions:

Are power circuit reclosers, reclosing relays, closing circuits and auto-restoration schemes covered in this Standard?

Yes. Automatic Reclosing includes reclosing relays and the associated dc control circuitry. Section 4.2.6 of the Applicability specifically limits the applicable reclosing relays to:

4.2.6 Automatic Reclosing

4.2.6.1 Automatic Reclosing applied on the terminals of Elements connected to the BES bus located at generating plant substations where the total installed gross generating plant capacity is greater than the gross capacity of the largest BES generating unit within the Balancing Authority Area or, if a member of a Reserve Sharing Group, the largest generating unit within the Reserve Sharing Group.

4.2.6.2 Automatic Reclosing applied on the terminals of all BES Elements at substations one bus away from generating plants specified in Section 4.2.6.1 when the substation is less than 10 circuit-miles from the generating plant substation.

4.2.6.3 Automatic Reclosing applied as an integral part of aRAS specified in Section 4.2.4. Further, Footnote 1 to Applicability Section 4.2.6 establishes that Automatic Reclosing addressed in 4.2.6.1 and 4.2.6.2 may be excluded if the equipment owner can demonstrate that a close-in three-phase fault present for twice the normal clearing time (capturing a minimum trip-close-trip time delay) does not result in a total loss of gross generation in the Interconnection exceeding the gross capacity of the largest relevant BES generating unit where the Automatic Reclosing is applied.

Additionally, Footnote 2 to Applicability Section 4.2.6.1 advises that the entity's PSMP needs to remain current regarding the applicability of Automatic Reclosing Components relative to the largest generating unit within the Balancing Authority Area or Reserve Sharing Group.

The Applicability as detailed above was recommended by the NERC System Analysis and Modeling Subcommittee (SAMS) after a lengthy review of the use of reclosing within the BES. SAMS concluded that automatic reclosing is largely implemented throughout the BES as an operating convenience, and that automatic reclosing mal-performance affects BES reliability only when the reclosing is part of a Remedial Action Schemes, or when premature autoreclosing has the potential to cause generating unit or plant instability. A technical report, "Considerations for Maintenance and Testing of Autoreclosing Schemes — November 2012", is referenced in PRC-005-3 and provides a more detailed discussion of these concerns.

Why did the standard drafting team not include IEEE device numbers to describe Automatic Reclosing Relays?

The drafting team elected not to include IEEE device numbers to describe Automatic Reclosing because Automatic Reclosing component type could be a stand-alone electromechanical relay; or could be the 79 function within a microprocessor based multi-function relay(11).

Is a sync-check (25) relay included in the Automatic Reclosing Control Circuitry?

Where sync-check relays are included in an Automatic Reclosing scheme that is part of an RAS, the sync-check would be included in the control circuitry (Table 4-2(b)). Where sync-check relays are included in an Automatic Reclosing scheme that is not part of an RAS, the sync-check would not be included in the control circuitry (Table 4-2(a)).

The SDT asserts that a sync-check (25) relay does not initiate closing but rather enables or disables closing and is not considered a part of the actual Automatic Reclosing control circuitry when not part of an RAS.

How do I interpret Applicability Section 4.2.6 to determine applicability in the following examples:

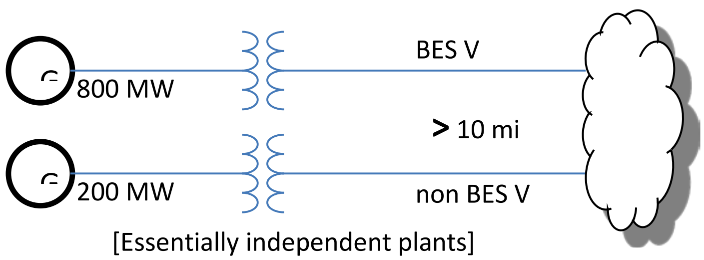
At my generating plant substation, I have a total of 800 MW connected to one voltage level and 200 MW connected to another voltage level. How do I determine my gross capacity? Where do I consider Automatic Reclosing to be applicable?

Scenario number 1:

The 800 MW of generation is connected to a BES voltage level bus, the 200 MW is connected to a non-BES voltage level bus, and there is no connection between the two buses locally or within 10 circuit miles from the generating plant substation. The largest single unit in the BA area is 750 MW.

In this case, the total installed gross generating capacity would be 800 MW. The two units are essentially independent plants.

The BES voltage level bus is considered to be the bus to which the 800 MW of generation is connected. Any BES Automatic Reclosing at this location, as well as other locations within 10 circuit miles, is considered to be applicable because 800 MW exceeds the largest single unit in the BA area.



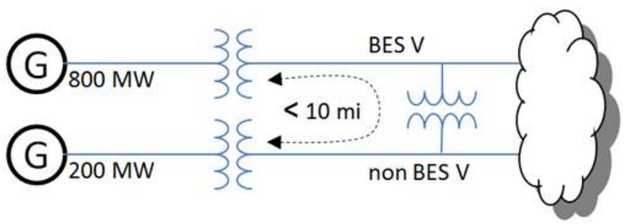
Gross Capacity	Automatic Reclosing in scope
800 MW	BES V

Scenario number 2:

The 800 MW of generation is connected to a BES voltage level bus, the 200 MW unit is connected to a non-BES voltage level bus, and there is a connection between the two buses locally or within 10 circuit miles from the generating plant substation. The largest single unit in the BA area is 750 MW.

In this case, reclosing into a fault on the BES system could impact the stability of the non-BES-connected generating units. Therefore, the total installed gross generating capacity would be 1000 MW.

The BES voltage level bus is considered to be the bus to which the 800 MW of generation is connected. Any BES Automatic Reclosing at this location, as well as other locations within 10 circuit miles, is considered to be applicable because total of 1000 MW exceeds the largest single unit in the BA area. However, the Automatic Reclosing on the non-BES voltage level bus is not applicable.



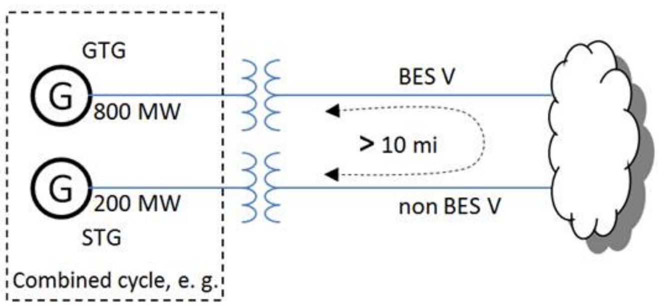
Gross Capacity	**Automatic Reclosing in scope**
1000 MW	BES V

Scenario number 3:

The 800 MW of generation is connected to a BES voltage level bus, the 200 MW unit is connected to a non-BES voltage level bus, and there is no connection between the two buses locally or within 10 circuit miles from the generating plant substation but the generating units connected at the BES voltage level do not operate independently of the units connected at the non BES voltage level (e.g., a combined cycle facility where 800 MW of combustion turbines are connected at a BES voltage level whose exhaust is used to power a 200 MW steam unit connected to a non BES voltage level. The largest single unit in the BA area is 750 MW.

In this case, the total installed gross generating capacity would be 1000 MW. Therefore, reclosing into a fault on the BES voltage level would result in a loss of the 800 MW combustion turbines and subsequently result in the loss of the 200 MW steam unit because of the loss of the heat source to its boiler.

The BES voltage level bus is considered to be the bus to which the 800 MW of generation is connected. Any BES Automatic Reclosing at this location, as well as other locations within 10 circuit miles, is considered to be applicable because total of 1000 MW exceeds the largest single unit in the BA area. However, the Automatic Reclosing on the non-BES voltage level bus is not applicable.



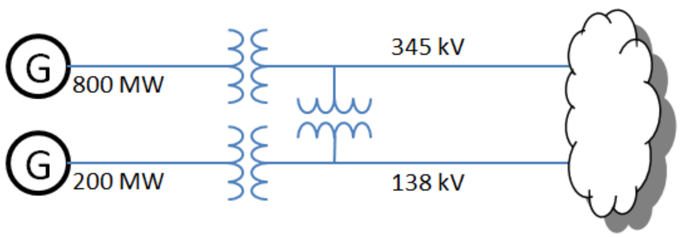
<u>**Gross Capacity**</u>	<u>**Automatic Reclosing in scope**</u>
1000 MW	BES V

Scenario 4

The 800 MW of generation is connected at 345 kV and the 200 MW is connected at 138 kV with an autotransformer at the generating plant substation connecting the two voltage levels. The largest single unit in the BA area is 900 MW.

In this case, the total installed gross generating capacity would be 1000 MW and section 4.2.6.1 would be applicable to both the 345 kV Automatic Reclosing Components and the 138 kV Automatic Reclosing Components, since the total capacity of 1000 MW is larger than the largest single unit in the BA area.

However, if the 345 kV and the 138 kV systems can be shown to be uncoupled such that the 138 kV reclosing relays will not affect the stability of the 345 kV generating units then the 138 kV Automatic Reclosing Components need not be included per section 4.2.6.1.



Gross Capacity	**Automatic Reclosing in scope**
1000 MW	BOTH*

* The study detailed in Footnote 1 of the draft standard may eliminate the 138 kV Automatic Reclosing Components and/or the 345 kV Automatic Reclosing Components

Why does 4.2.6.2 specify “10 circuit miles”?

As noted in “Considerations for Maintenance and Testing of Autoreclosing Schemes — November 2012”, transmission line impedance on the order of one mile away typically provides adequate impedance to prevent generating unit instability and a 10 mile threshold provides sufficient margin.

Should I use MVA or MW when determining the installed gross generating plant capacity?

Be consistent with the rating used by the Balancing Authority for the largest BES generating unit within their area.

What value should we use for generating plant capacity in 4.2.6.1?

Use the value reported to the Balance Authority for generating plant capacity for planning and modeling purposes. This can be nameplate or other values based on generating plant limitations such as boiler or turbine ratings.

What is considered to be “one bus away” from the generation?

The BES voltage level bus is considered to be the generating plant substation bus to which the generator step-up transformer is connected. “One bus away” is the next bus, connected by either a transmission line or transformer.

I use my protective relays only as sources of metered quantities and breaker status for SCADA and EMS through a substation distributed RTU or data concentrator to the control center. What are the maintenance requirements for the relays?

This standard addresses Protection Systems that are installed for the purpose of detecting Faults on BES Elements (lines, buses, transformers, etc.). Protective relays, providing only the functions mentioned in the question, are not included.

Are Reverse Power Relays installed on the low-voltage side of distribution banks considered to be components of “Protection Systems that are installed for the purpose of detecting Faults on BES Elements (lines, buses, transformers, etc.)”?

Reverse power relays are often installed to detect situations where the transmission source becomes de-energized and the distribution bank remains energized from a source on the low-voltage side of the transformer and the settings are calculated based on the charging current of the transformer from the low-voltage side. Although these relays may operate as a result of a fault on a BES element, they are not ‘installed for the purpose of detecting’ these faults.

Why is the maintenance of Sudden Pressure Relaying being addressed in PRC-005-4?

Proper performance of Sudden Pressure Relaying supports the reliability of the BES because fault pressure relays can detect rapid changes in gas pressure, oil pressure, or oil flow that are indicative of faults within liquid-filled, wire-wound equipment such as turn-to-turn faults which may be undetected by Protection Systems. Additionally, Sudden Pressure

Relaying can quickly detect faults and operate to limit damage to liquid-filled, wire-wound equipment.

What type of devices are classified as fault pressure relay?

There are three main types of fault pressure relays; rapid gas pressure rise, rapid oil pressure rise, and rapid oil flow devices.

Rapid gas pressure devices monitor the pressure in the space above the oil (or other liquid), and initiate tripping action for a rapid rise in gas pressure resulting from the rapid expansion of the liquid caused by a fault. The sensor is located in the gas space.

Rapid oil pressure devices monitor the pressure in the oil (or other liquid), and initiate tripping action for a rapid pressure rise caused by a fault. The sensor is located in the liquid.

Rapid oil flow devices ("Buchholz") monitor the liquid flow between a transformer/reactor and its conservator. Normal liquid flow occurs continuously with ambient temperature changes and with internal heating from loading and does not operate the rapid oil flow device. However, when an internal arc happens a sudden expansion of liquid can be monitored as rapid liquid flow from the transformer into the conservator resulting in actuation of the rapid oil flow device.

Are sudden pressure relays that only initiate an alarm included in the scope of PRC-005-4?

No, the definition of Sudden Pressure Relaying specifies only those that trip an interrupting device(s) to isolate the equipment it is monitoring.

Are pressure relief devices included in the scope of PRC-005-4?

No. PRDs are not included in the Sudden Pressure Relaying definition.

Is Sudden Pressure Relaying installed on distribution transformers included in PRC-005-4?

No, Applicability 4.2.1, 4.2.5.2, 4.2.5.3, 4.2.5.4, explicitly describe what Sudden Pressure Relaying is included within the standard.

Are non-electrical sensing devices (other than fault pressure relays) such as low oil level or high winding temperatures included in PRC-005-4?

No, based on the SPCS technical document, "Sudden Pressure Relays and Other Devices that Respond to Non-Electrical Quantities – December 2013," the only applicable non-electrical sensing devices are Sudden Pressure Relays.

The standard specifically mentions auxiliary and lock-out relays. What is an auxiliary tripping relay?

An auxiliary relay, IEEE Device No. 94, is described in IEEE Standard C37.2-2008 as: "A device that functions to trip a circuit breaker, contactor, or equipment; to permit immediate tripping by other devices; or to prevent immediate reclosing of a circuit interrupter if it should open automatically, even though its closing circuit is maintained closed."

What is a lock-out relay?

A lock-out relay, IEEE Device No. 86, is described in IEEE Standard C37.2 as: “A device that trips and maintains the associated equipment or devices inoperative until it is reset by an operator, either locally or remotely.”

3. Protection System and Automatic Reclosing Product Generations

The likelihood of failure and the ability to observe the operational state of a critical Protection System and Automatic Reclosing both depend on the technological generation of the relays, as well as how long they have been in service. Unlike many other transmission asset groups, protection and control systems have seen dramatic technological changes spanning several generations. During the past 20 years, major functional advances are primarily due to the introduction of microprocessor technology for power system devices, such as primary measuring relays, monitoring devices, control Systems, and telecommunications equipment.

Modern microprocessor-based relays have six significant traits that impact a maintenance strategy:

- Self-monitoring capability - the processors can check themselves, peripheral circuits, and some connected substation inputs and outputs, such as trip coil continuity. Most relay users are aware that these relays have self-monitoring, but are not focusing on exactly what internal functions are actually being monitored. As explained further below, every element critical to the Protection System must be monitored, or else verified periodically.
- Ability to capture Fault records showing how the Protection System responded to a Fault in its zone of protection, or to a nearby Fault for which it is required not to operate.
- Ability to meter currents and voltages, as well as status of connected circuit breakers, continuously during non-Fault times. The relays can compute values, such as MW and MVAR line flows, that are sometimes used for operational purposes, such as SCADA.
- Data communications via ports that provide remote access to all of the results of Protection System monitoring, recording and measurement.
- Ability to trip or close circuit breakers and switches through the Protection System outputs, on command from remote data communications messages, or from relay front panel button requests.
- Construction from electronic components, some of which have shorter technical life or service life than electromechanical components of prior Protection System generations.

There have been significant advances in the technology behind the other components of Protection Systems. Microprocessors are now a part of battery chargers, associated communications equipment, voltage and current-measuring devices, and even the control circuitry (in the form of software-latches replacing lock-out relays, etc.).

Any Protection System component can have self-monitoring and alarming capability, not just relays. Because of this technology, extended time intervals can find their way into all components of the Protection System.

This standard also recognizes the distinct advantage of using advanced technology to justifiably defer or even eliminate traditional maintenance. Just as a hand-held calculator does not require routine testing and calibration, neither does a calculation buried in a microprocessor-based device that results in a "lock-out." Thus, the software-latch 86 that replaces an electro-mechanical 86 does not require routine trip testing. Any trip circuitry associated with the "soft 86" would still need applicable verification activities performed, but the actual "86" does not have to be "electrically operated" or even toggled.

4. Definitions

Protection System Maintenance Program (PSMP) — An ongoing program by which Protection System, Automatic Reclosing and Sudden Pressure Relaying Components are kept in working order and proper operation of malfunctioning Components is restored. A maintenance program for a specific Component includes one or more of the following activities:

- Verify — Determine that the Component is functioning correctly.
- Monitor — Observe the routine in-service operation of the Component.
- Test — Apply signals to a Component to observe functional performance or output behavior, or to diagnose problems.
- Inspect — Detect visible signs of Component failure, reduced performance and degradation.
- Calibrate — Adjust the operating threshold or measurement accuracy of a measuring element to meet the intended performance requirement.

Automatic Reclosing – Includes the following Components:

- Reclosing relay
- Control circuitry associated with the reclosing relay.

Sudden Pressure Relaying – A system that trips an interrupting device(s) to isolate the equipment it is monitoring and includes the following Components:

- Fault pressure relay – a mechanical relay or device that detects rapid changes in gas pressure, oil pressure, or oil flow that are indicative of faults within liquid-filled, wire-wound equipment
- Control circuitry associated with a fault pressure relay

Unresolved Maintenance Issue – A deficiency identified during a maintenance activity that causes the component to not meet the intended performance, cannot be corrected during the maintenance interval, and requires follow-up corrective action.

Segment – Components of a consistent design standard, or a particular model or type from a single manufacturer that typically share other common elements. Consistent performance is expected across the entire population of a Segment. A Segment must contain at least sixty (60) individual Components.

Component Type –

- Any one of the five specific elements of a Protection System.
- Any one of the two specific elements of Automatic Reclosing.
- Any one of the two specific elements of Sudden Pressure Relaying.

Component – Any individual discrete piece of equipment included in a Protection System, Automatic Reclosing, or Sudden Pressure Relaying.

Countable Event – A failure of a Component requiring repair or replacement, any condition discovered during the maintenance activities in Tables 1-1 through 1-5, Table 3, Tables 4-1 through 4-2, and Table 5, which requires corrective action or a Protection System Misoperation attributed to hardware failure or calibration failure. Misoperations due to product design errors, software errors, relay settings different from specified settings, Protection System Component, Automatic Reclosing or Sudden Pressure Relaying configuration or application errors are not included in Countable Events.

4.1 Frequently Asked Questions:

Why does PRC-005-4 not specifically require maintenance and testing procedures, as reflected in the previous standard, PRC-005-1?

PRC-005-1 does not require detailed maintenance and testing procedures, but instead requires summaries of such procedures, and is not clear on what is actually required. PRC-005-4 requires a documented maintenance program, and is focused on establishing requirements rather than prescribing methodology to meet those requirements. Between the activities identified in the Tables 1-1 through 1-5, Table 2, Table 3, and Table 4 (collectively the "Tables"), and the various components of the definition established for a "Protection System Maintenance Program," PRC-005-4 establishes the activities and time basis for a Protection System Maintenance Program to a level of detail not previously required.

Please clarify what is meant by "restore" in the definition of maintenance.

The description of "restore" in the definition of a Protection System Maintenance Program addresses corrective activities necessary to assure that the component is returned to working order following the discovery of its failure or malfunction. The Maintenance Activities specified in the Tables do not present any requirements related to Restoration; R5 of the standard does require that the entity "shall demonstrate efforts to correct any identified Unresolved Maintenance Issues." Some examples of restoration (or correction of Unresolved Maintenance Issues) include, but are not limited to, replacement of capacitors in distance relays to bring them to working order; replacement of relays, or other Protection System components, to bring the Protection System to working order; upgrade of electromechanical or solid-state protective relays to microprocessor-based relays following the discovery of failed components. Restoration, as used in this context, is not to be confused with restoration rules as used in system operations. Maintenance activity necessarily includes both the detection of problems and the repairs needed to eliminate those problems. This standard does not identify all of the Protection System problems that must be detected and eliminated, rather it is the intent of this standard that an entity determines the necessary working order for their various devices, and keeps them in working order. If an equipment item is repaired or replaced, then the entity can restart the maintenance-time-interval-clock, if desired; however, the replacement of equipment does not remove any documentation requirements that would have been required to verify compliance with time-interval requirements. In other words, do not discard maintenance data that goes to verify your work.

The retention of documentation for new and/or replaced equipment is all about proving that the maintenance intervals had been in compliance. For example, a long-range plan of upgrades might lead an entity to ignore required maintenance; retaining the evidence of prior maintenance that existed before any retirements and upgrades proves compliance with the standard.

Please clarify what is meant by "…demonstrate efforts to correct an Unresolved Maintenance Issue…"; why not measure the completion of the corrective action?

Management of completion of the identified Unresolved Maintenance Issue is a complex topic that falls outside of the scope of this standard. There can be any number of supply, process and management problems that make setting repair deadlines impossible. The SDT specifically chose the phrase "demonstrate efforts to correct" (with guidance from NERC Staff) because of the concern that many more complex Unresolved Maintenance Issues might require greater than the remaining maintenance interval to resolve (and yet still be a "closed-end process"). For example, a problem might be identified on a VRLA battery during a six-month check. In instances such as one that requiring battery replacement as part of the long-term resolution, it is highly unlikely that the battery could be replaced in time to meet the six-calendar-month requirement for this maintenance activity. The SDT does not believe entities should be found in violation of a maintenance program requirement because of the inability to complete a remediation program within the original maintenance interval. The SDT does believe corrective actions should be timely, but concludes it would be impossible to postulate all possible remediation projects; and, therefore, impossible to specify bounding time frames for resolution of all possible Unresolved Maintenance Issues, or what documentation might be sufficient to provide proof that effective corrective action is being undertaken.

5. Time-Based Maintenance (TBM) Programs

Time-based maintenance is the process in which Protection System, Automatic Reclosing and Sudden Pressure Relaying Components are maintained or verified according to a time schedule. The scheduled program often calls for technicians to travel to the physical site and perform a functional test on Protection System components. However, some components of a TBM program may be conducted from a remote location - for example, tripping a circuit breaker by communicating a trip command to a microprocessor relay to determine if the entire Protection System tripping chain is able to operate the breaker. Similarly, all Protection System, and Sudden Pressure Relaying Components can have the ability to remotely conduct tests, either on-command or routinely; the running of these tests can extend the time interval between hands-on maintenance activities.

5.1 Maintenance Practices

Maintenance and testing programs often incorporate the following types of maintenance practices:

- TBM – time-based maintenance – externally prescribed maximum maintenance or testing intervals are applied for components or groups of components. The intervals may have been developed from prior experience or manufacturers' recommendations. The TBM verification interval is based on a variety of factors, including experience of the particular asset owner, collective experiences of several asset owners who are members of a country or regional council, etc. The maintenance intervals are fixed and may range in number of months or in years.

  TBM can include review of recent power system events near the particular terminal. Operating records may verify that some portion of the Protection System has operated correctly since the last test occurred. If specific protection scheme components have demonstrated correct performance within specifications, the maintenance test time clock can be reset for those components.

- PBM – Performance-Based Maintenance - intervals are established based on analytical or historical results of TBM failure rates on a statistically significant population of similar components. Some level of TBM is generally followed. Statistical analyses accompanied by adjustments to maintenance intervals are used to justify continued use of PBM-developed extended intervals when test failures or in-service failures occur infrequently.

- CBM – condition-based maintenance – continuously or frequently reported results from non-disruptive self-monitoring of components demonstrate operational status as those components remain in service. Whatever is verified by CBM does not require manual testing, but taking advantage of this requires precise technical focus on exactly what parts are included as part of the self-diagnostics. While the term "Condition-Based-Maintenance" (CBM) is no longer used within the standard itself, it is important to note that the concepts of CBM are a part of the standard (in the form of extended time intervals through status-monitoring). These extended time intervals are only allowed (in the absence of PBM) if the condition of the device is monitored (CBM). As a consequence of the "monitored-basis-time-intervals" existing within the standard, the explanatory

discussions within this Supplementary Reference concerned with CBM will remain in this reference and are discussed as CBM.

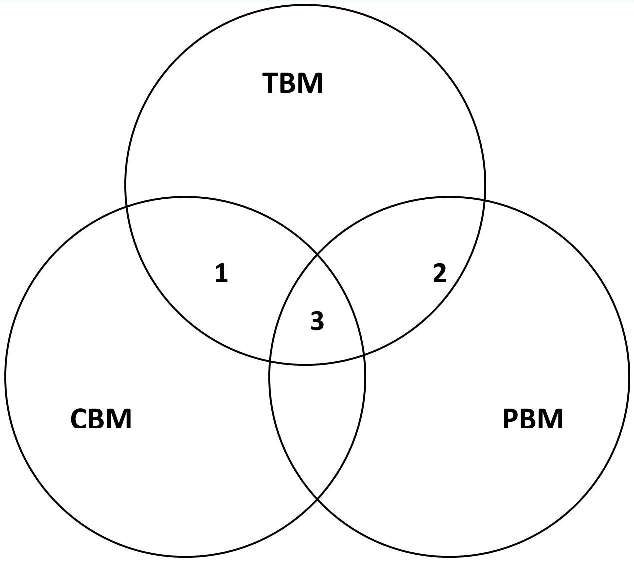
Microprocessor-based Protection System or Automatic Reclosing Components that perform continuous self-monitoring verify correct operation of most components within the device. Self-monitoring capabilities may include battery continuity, float voltages, unintentional grounds, the ac signal inputs to a relay, analog measuring circuits, processors and memory for measurement, protection, and data communications, trip circuit monitoring, and protection or data communications signals (and many, many more measurements). For those conditions, failure of a self-monitoring routine generates an alarm and may inhibit operation to avoid false trips. When internal components, such as critical output relay contacts, are not equipped with self-monitoring, they can be manually tested. The method of testing may be local or remote, or through inherent performance of the scheme during a system event.

The TBM is the overarching maintenance process of which the other types are subsets. Unlike TBM, PBM intervals are adjusted based on good or bad experiences. The CBM verification intervals can be hours, or even milliseconds between non-disruptive self-monitoring checks within or around components as they remain in service.

TBM, PBM, and CBM can be combined for individual components, or within a complete Protection System. The following diagram illustrates the relationship between various types of maintenance practices described in this section. In the Venn diagram, the overlapping regions show the relationship of TBM with PBM historical information and the inherent continuous monitoring offered through CBM.

This figure shows:

- Region 1: The TBM intervals that are increased based on known reported operational condition of individual components that are monitoring themselves.
- Region 2: The TBM intervals that are adjusted up or down based on results of analysis of maintenance history of statistically significant population of similar products that have been subject to TBM.
- Region 3: Optimal TBM intervals based on regions 1 and 2.



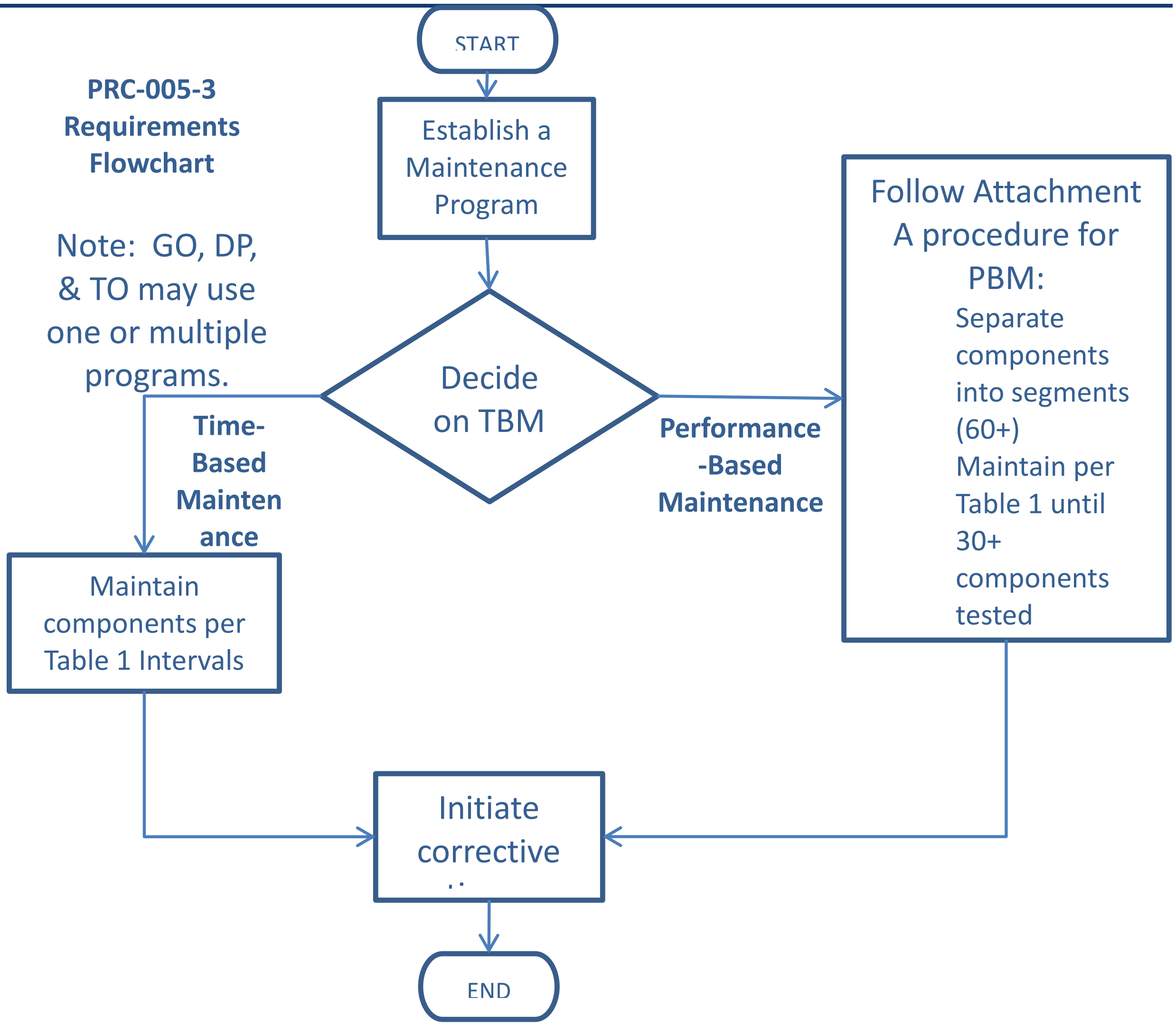
Relationship of time-based maintenance types

5.1.1 Frequently Asked Questions:

The standard seems very complicated, and is difficult to understand. Can it be simplified?

Because the standard is establishing parameters for condition-based Maintenance (R1) and Performance-Based Maintenance (R2), in addition to simple time-based Maintenance, it does appear to be complicated. At its simplest, an entity needs to ONLY perform time-based maintenance according to the unmonitored rows of the Tables. If an entity then wishes to take advantage of monitoring on its Protection System components and its available lengthened time intervals, then it may, as long as the component has the listed monitoring attributes. If an entity wishes to use historical performance of its Protection System components to perform Performance-Based Maintenance, then R2 applies.

Please see the following diagram, which provides a "flow chart" of the standard.



We have an electromechanical (unmonitored) relay that has a trip output to a lockout relay (unmonitored) which trips our transformer off-line by tripping the transformer's high-side and low-side circuit breakers. What testing must be done for this system?

This system is made up of components that are all unmonitored. Assuming a time-based Protection System Maintenance Program schedule (as opposed to a Performance-Based maintenance program), each component must be maintained per the most frequent hands-on activities listed in the Tables.

5.2 Extending Time-Based Maintenance

All maintenance is fundamentally time-based. Default time-based intervals are commonly established to assure proper functioning of each component of the Protection System, when data on the reliability of the components is not available other than observations from time-based maintenance. The following factors may influence the established default intervals:

- If continuous indication of the functional condition of a component is available (from relays or chargers or any self-monitoring device), then the intervals may be extended, or manual testing may be eliminated. This is referred to as condition-based maintenance or

CBM. CBM is valid only for precisely the components subject to monitoring. In the case of microprocessor-based relays, self-monitoring may not include automated diagnostics of every component within a microprocessor.

- Previous maintenance history for a group of components of a common type may indicate that the maintenance intervals can be extended, while still achieving the desired level of performance. This is referred to as Performance-Based Maintenance, or PBM. It is also sometimes referred to as reliability-centered maintenance, or RCM; but PBM is used in this document.
- Observed proper operation of a component may be regarded as a maintenance verification of the respective component or element in a microprocessor-based device. For such an observation, the maintenance interval may be reset only to the degree that can be verified by data available on the operation. For example, the trip of an electromechanical relay for a Fault verifies the trip contact and trip path, but only through the relays in series that actually operated; one operation of this relay cannot verify correct calibration.

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. The improper application of test signals may cause failure of a component. For example, in electromechanical overcurrent relays, test currents have been known to destroy convolution springs.

In addition, maintenance usually takes the component out of service, during which time it is not able to perform its function. Cutout switch failures, or failure to restore switch position, commonly lead to protection failures.

5.2.1 Frequently Asked Questions:

If I show the protective device out of service while it is being repaired, then can I add it back as a new protective device when it returns? If not, my relay testing history would show that I was out of compliance for the last maintenance cycle.

The maintenance and testing requirements (R5) (in essence) state "…shall demonstrate efforts to correct any identified Unresolved Maintenance Issues." The type of corrective activity is not stated; however it could include repairs or replacements.

Your documentation requirements will increase, of course, to demonstrate that your device tested bad and had corrective actions initiated. Your regional entity could very well ask for documentation showing status of your corrective actions.

6. Condition-Based Maintenance (CBM) Programs

Condition-based maintenance is the process of gathering and monitoring the information available from modern microprocessor-based relays and other intelligent electronic devices (IEDs) that monitor Protection System or Automatic Reclosing elements. These devices generate monitoring information during normal operation, and the information can be assessed at a convenient location remote from the substation. The information from these relays and IEDs is divided into two basic types:

1. Information can come from background self-monitoring processes, programmed by the manufacturer, or by the user in device logic settings. The results are presented by alarm contacts or points, front panel indications, and by data communications messages.
2. Information can come from event logs, captured files, and/or oscillographic records for Faults and Disturbances, metered values, and binary input status reports. Some of these are available on the device front panel display, but may be available via data communications ports. Large files of Fault information can only be retrieved via data communications. These results comprise a mass of data that must be further analyzed for evidence of the operational condition of the Protection System.

Using these two types of information, the user can develop an effective maintenance program carried out mostly from a central location remote from the substation. This approach offers the following advantages:

Non-invasive Maintenance: The system is kept in its normal operating state, without human intervention for checking. This reduces risk of damage, or risk of leaving the system in an inoperable state after a manual test. Experience has shown that keeping human hands away from equipment known to be working correctly enhances reliability.

Virtually Continuous Monitoring: CBM will report many hardware failure problems for repair within seconds or minutes of when they happen. This reduces the percentage of problems that are discovered through incorrect relaying performance. By contrast, a hardware failure discovered by TBM may have been there for much of the time interval between tests, and there is a good chance that some devices will show health problems by incorrect operation before being caught in the next test round. The frequent or continuous nature of CBM makes the effective verification interval far shorter than any required TBM maximum interval. To use the extended time intervals available through Condition Based Maintenance, simply look for the rows in the Tables that refer to monitored items.

6.1 Frequently Asked Questions:

My microprocessor relays and dc circuit alarms are contained on relay panels in a 24-hour attended control room. Does this qualify as an extended time interval condition-based (monitored) system?

Yes, provided the station attendant (plant operator, etc.) monitors the alarms and other indications (comparable to the monitoring attributes) and reports them within the given time limits that are stated in the criteria of the Tables.

When documenting the basis for inclusion of components into the appropriate levels of monitoring, as per Requirement R1 (Part 1.2) of the standard, is it necessary to provide this documentation about the device by listing of every component and the specific monitoring attributes of each device?

No. While maintaining this documentation on the device level would certainly be permissible, it is not necessary. Global statements can be made to document appropriate levels of monitoring for the entire population of a component type or portion thereof.

For example, it would be permissible to document the conclusion that all BES substation dc supply battery chargers are monitored by stating the following within the program description:

> "All substation dc supply battery chargers are considered monitored and subject to the rows for monitored equipment of Table 1-4 requirements, as all substation dc supply battery chargers are equipped with dc voltage alarms and ground detection alarms that are sent to the manned control center."

Similarly, it would be acceptable to use a combination of a global statement and a device-level list of exclusions. Example:

> "Except as noted below, all substation dc supply battery chargers are considered monitored and subject to the rows for monitored equipment of Table 1-4 requirements, as all substation dc supply battery chargers are equipped with dc voltage alarms and ground detection alarms that are sent to the manned control center. The dc supply battery chargers of Substation X, Substation Y, and Substation Z are considered unmonitored and subject to the rows for unmonitored equipment in Table 1-4 requirements, as they are not equipped with ground detection capability."

Regardless whether this documentation is provided by device listing of monitoring attributes, by global statements of the monitoring attributes of an entire population of component types, or by some combination of these methods, it should be noted that auditors may request supporting drawings or other documentation necessary to validate the inclusion of the device(s) within the appropriate level of monitoring. This supporting background information need not be maintained within the program document structure, but should be retrievable if requested by an auditor.

7. Time-Based Versus Condition-Based Maintenance

Time-based and condition-based (or monitored) maintenance programs are both acceptable, if implemented according to technically sound requirements. Practical programs can employ a *combination of time-based and condition-based maintenance.* The standard requirements introduce the concept of optionally using condition monitoring as a documented element of a maintenance program.

The Federal Energy Regulatory Commission (FERC), in its Order Number 693 Final Rule, dated March 16, 2007 (18 CFR Part 40, Docket No. RM06-16-000) on Mandatory Reliability Standards for the Bulk-Power System, directed NERC to submit a modification to PRC-005-1b that includes a requirement that maintenance and testing of a Protection System must be carried out within a maximum allowable interval that is appropriate to the type of the Protection System and its impact on the reliability of the Bulk Power System. Accordingly, this Supplementary Reference Paper refers to the specific maximum allowable intervals in PRC-005-4. The defined time limits allow for longer time intervals if the maintained component is monitored.

A key feature of condition-based monitoring is that it effectively reduces the time delay between the moment of a protection failure and time the Protection System or Automatic Reclosing owner knows about it, for the monitored segments of the Protection System. In some cases, the verification is practically continuous - the time interval between verifications is minutes or seconds. Thus, technically sound, condition-based verification, meets the verification requirements of the FERC order even more effectively than the strictly time-based tests of the same system components.

The result is that:

This NERC standard permits utilities to use a technically sound approach and to take advantage of remote monitoring, data analysis, and control capabilities of modern Protection System and Automatic Reclosing Components to reduce the need for periodic site visits and invasive testing of components by on-site technicians. This periodic testing must be conducted within the maximum time intervals specified in the Tables of PRC-005-4.

7.1 Frequently Asked Questions:

What is a Calendar Year?

Calendar Year - January 1 through December 31 of any year. As an example, if an event occurred on June 17, 2009 and is on a “One Calendar Year Interval,” the next event would have to occur on or before December 31, 2010.

Please provide an example of “4 Calendar Months”.

If a maintenance activity is described as being needed every four Calendar Months then it is performed in a (given) month and due again four months later. For example a battery bank is inspected in month number 1 then it is due again before the end of the month number5. And specifically consider that you perform your battery inspection on January 3, 2010 then it must be inspected again before the end of May. Another example could be that a four-month inspection

was performed in January is due in May, but if performed in March (instead of May) would still be due four months later therefore the activity is due again July. Basically every “four Calendar Months” means to add four months from the last time the activity was performed.

Please provide an example of the unmonitored versus other levels of monitoring available?

An unmonitored Protection System has no monitoring and alarm circuits on the Protection System components. A Protection System component that has monitoring attributes but no alarm output connected is considered to be unmonitored.

A monitored Protection System or an individual monitored component of a Protection System has monitoring and alarm circuits on the Protection System components. The alarm circuits must alert, within 24 hours, a location wherein corrective action can be initiated. This location might be, but is not limited to, an Operations Center, Dispatch Office, Maintenance Center or even a portable SCADA system.

There can be a combination of monitored and unmonitored Protection Systems within any given scheme, substation or plant; there can also be a combination of monitored and unmonitored components within any given Protection System.

Example #1: A combination of monitored and unmonitored components within a given Protection System might be:

- A microprocessor relay with an internal alarm connected to SCADA to alert 24-hr staffed operations center; it has internal self-diagnosis and alarming. (monitored)
- Instrumentation transformers, with no monitoring, connected as inputs to that relay. (unmonitored)
- A vented Lead-Acid battery with a low voltage alarm for the station dc supply voltage and an unintentional grounds detection alarm connected to SCADA. (monitoring varies)
- A circuit breaker with a trip coil, and the trip circuit is not monitored. (unmonitored)

Given the particular components and conditions, and using Table 1 and Table 2, the particular components have maximum activity intervals of:

<u>Every four calendar months</u>, inspect:

- Electrolyte level (station dc supply voltage and unintentional ground detection is being maintained more frequently by the monitoring system).

<u>Every 18 calendar months</u>, verify/inspect the following:

- Battery bank ohmic values to station battery baseline (if performance tests are not opted)
- Battery charger float voltage
- Battery rack integrity
- Cell condition of all individual battery cells (where visible)
- Battery continuity
- Battery terminal connection resistance

- Battery cell-to-cell resistance (where available to measure)

Every six calendar years, perform/verify the following:

- Battery performance test (if internal ohmic tests or other measurements indicative of battery performance are not opted)
- Verify that each trip coil is able to operate the circuit breaker, interrupting device, or mitigating device
- For electromechanical lock-out relays, electrical operation of electromechanical trip

Every 12 calendar years, verify the following:

- Microprocessor relay settings are as specified
- Operation of the microprocessor's relay inputs and outputs that are essential to proper functioning of the Protection System
- Acceptable measurement of power System input values seen by the microprocessor protective relay
- Verify that current and voltage signal values are provided to the protective relays
- Protection System component monitoring for the battery system signals are conveyed to a location where corrective action can be initiated
- The microprocessor relay alarm signals are conveyed to a location where corrective action can be initiated
- Verify all trip paths in the control circuitry associated with protective functions through the trip coil(s) of the circuit breakers or other interrupting devices
- Auxiliary outputs that are in the trip path shall be maintained as detailed in Table 1-5 of the standard under the 'Unmonitored Control Circuitry Associated with Protective Functions" section'
- Auxiliary outputs not in a trip path (i.e., annunciation or DME input) are not required, by this standard, to be checked

Example #2: A combination of monitored and unmonitored components within a given Protection System might be:

- A microprocessor relay with integral alarm that is not connected to SCADA. (unmonitored)
- Current and voltage signal values, with no monitoring, connected as inputs to that relay. (unmonitored)
- A vented lead-acid battery with a low voltage alarm for the station dc supply voltage and an unintentional grounds detection alarm connected to SCADA. (monitoring varies)
- A circuit breaker with a trip coil, with no circuits monitored. (unmonitored)

Given the particular components and conditions, and using the Table 1 (Maximum Allowable Testing Intervals and Maintenance Activities) and Table 2 (Alarming Paths and Monitoring), the particular components have maximum activity intervals of:

__Every four calendar months__, inspect:

- Electrolyte level (station dc supply voltage and unintentional ground detection is being maintained more frequently by the monitoring system)

__Every 18 calendar months__, verify/inspect the following:

- Battery bank trending of ohmic values or other measurements indicative of battery performance to station battery baseline (if performance tests are not opted)
- Battery charger float voltage
- Battery rack integrity
- Cell condition of all individual battery cells (where visible)
- Battery continuity
- Battery terminal connection resistance
- Battery cell-to-cell resistance (where available to measure)

__Every six calendar years__, verify/perform the following:

- Verify operation of the relay inputs and outputs that are essential to proper functioning of the Protection System
- Verify acceptable measurement of power system input values as seen by the relays
- Verify that each trip coil is able to operate the circuit breaker, interrupting device, or mitigating device
- For electromechanical lock-out relays, electrical operation of electromechanical trip
- Battery performance test (if internal ohmic tests are not opted)

__Every 12 calendar years__, verify the following:

- Current and voltage signal values are provided to the protective relays
- Protection System component monitoring for the battery system signals are conveyed to a location where corrective action can be initiated
- All trip paths in the control circuitry associated with protective functions through the trip coil(s) of the circuit breakers or other interrupting devices
- Auxiliary outputs that are in the trip path shall be maintained, as detailed in Table 1-5 of the standard under the Unmonitored Control Circuitry Associated with Protective Functions" section
- Auxiliary outputs not in a trip path (i.e., annunciation or DME input) are not required, by this standard, to be checked

Example #3: A combination of monitored and unmonitored components within a given Protection System might be:

- A microprocessor relay with alarm connected to SCADA to alert 24-hr staffed operations center; it has internal self-diagnosis and alarms. (monitored)
- Current and voltage signal values, with monitoring, connected as inputs to that relay (monitored)

- Vented Lead-Acid battery without any alarms connected to SCADA (unmonitored)
- Circuit breaker with a trip coil, with no circuits monitored (unmonitored)

Given the particular components, conditions, and using the Table 1 (Maximum Allowable Testing Intervals and Maintenance Activities) and Table 2 (Alarming Paths and Monitoring), the particular components shall have maximum activity intervals of:

Every four calendar months, verify/inspect the following:

- Station dc supply voltage
- For unintentional grounds
- Electrolyte level

Every 18 calendar months, verify/inspect the following:

- Battery bank trending of ohmic values or other measurements indicative of battery performance to station battery baseline (if performance tests are not opted)
- Battery charger float voltage
- Battery rack integrity
- Battery continuity
- Battery terminal connection resistance
- Battery cell-to-cell resistance (where available to measure)
- Condition of all individual battery cells (where visible)

Every six calendar years, perform/verify the following:

- Battery performance test (if internal ohmic tests or other measurements indicative of battery performance are not opted)
- Verify that each trip coil is able to operate the circuit breaker, interrupting device, or mitigating device
- For electromechanical lock-out relays, electrical operation of electromechanical trip

Every 12 calendar years, verify the following:

- The microprocessor relay alarm signals are conveyed to a location where corrective action can be taken
- Microprocessor relay settings are as specified
- Operation of the microprocessor's relay inputs and outputs that are essential to proper functioning of the Protection System
- Acceptable measurement of power system input values seen by the microprocessor protective relay
- Verify all trip paths in the control circuitry associated with protective functions through the trip coil(s) of the circuit breakers or other interrupting devices

- Auxiliary outputs that are in the trip path shall be maintained, as detailed in Table 1-5 of the standard under the Unmonitored Control Circuitry Associated with Protective Functions section
- Auxiliary outputs not in a trip path (i.e. annunciation or DME input) are not required, by this standard, to be checked

Why do components have different maintenance activities and intervals if they are monitored?

The intent behind different activities and intervals for monitored equipment is to allow less frequent manual intervention when more information is known about the condition of Protection System components. Condition-Based Maintenance is a valuable asset to improve reliability.

Can all components in a Protection System be monitored?

No. For some components in a Protection System, monitoring will not be relevant. For example, a battery will always need some kind of inspection.

We have a 30-year-old oil circuit breaker with a red indicating lamp on the substation relay panel that is illuminated only if there is continuity through the breaker trip coil. There is no SCADA monitor or relay monitor of this trip coil. The line protection relay package that trips this circuit breaker is a microprocessor relay that has an integral alarm relay that will assert on a number of conditions that includes a loss of power to the relay. This alarm contact connects to our SCADA system and alerts our 24-hour operations center of relay trouble when the alarm contact closes. This microprocessor relay trips the circuit breaker only and does not monitor trip coil continuity or other things such as trip current. Are the components monitored or not? How often must I perform maintenance?

The protective relay is monitored and can be maintained every 12 years, or when an Unresolved Maintenance Issue arises. The control circuitry can be maintained every 12 years. The circuit breaker trip coil(s) has to be electrically operated at least once every six years.

What is a mitigating device?

A mitigating device is the device that acts to respond as directed by a Remedial Action Schemes. It may be a breaker, valve, distributed control system, or any variety of other devices. This response may include tripping, closing, or other control actions.

8. Maximum Allowable Verification Intervals

The maximum allowable testing intervals and maintenance activities show how CBM with newer device types can reduce the need for many of the tests and site visits that older Protection System components require. As explained below, there are some sections of the Protection System that monitoring or data analysis may not verify. Verifying these sections of the Protection System or Automatic Reclosing requires some persistent TBM activity in the maintenance program. However, some of this TBM can be carried out remotely - for example, exercising a circuit breaker through the relay tripping circuits using the relay remote control capabilities can be used to verify function of one tripping path and proper trip coil operation, if there has been no Fault or routine operation to demonstrate performance of relay tripping circuits.

8.1 Maintenance Tests

Periodic maintenance testing is performed to ensure that the protection and control system is operating correctly after a time period of field installation. These tests may be used to ensure that individual components are still operating within acceptable performance parameters - this type of test is needed for components susceptible to degraded or changing characteristics due to aging and wear. Full system performance tests may be used to confirm that the total Protection System functions from measurement of power system values, to properly identifying Fault characteristics, to the operation of the interrupting devices.

8.1.1 Table of Maximum Allowable Verification Intervals

Table 1 (collectively known as Table 1, individually called out as Tables 1-1 through 1-5), Table 2, Table 3, Table 4-1 through Table 4-2, and Table 5 in the standard specify maximum allowable verification intervals for various generations of Protection Systems, Automatic Reclosing and Sudden Pressure Relaying and categories of equipment that comprise these systems. The right column indicates maintenance activities required for each category.

The types of components are illustrated in Figures 1 and 2 at the end of this paper. Figure 1 shows an example of telecommunications-assisted transmission Protection System comprising substation equipment at each terminal and a telecommunications channel for relaying between the two substations. Figure 2 shows an example of a generation Protection System. The various sub-systems of a Protection System that need to be verified are shown.

Non-distributed UFLS, UVLS, and RAS are additional categories of Table 1 that are not illustrated in these figures. Non-distributed UFLS, UVLS and RAS all use identical equipment as Protection Systems in the performance of their functions; and, therefore, have the same maintenance needs.

Distributed UFLS and UVLS Systems, which use local sensing on the distribution System and trip co-located non-BES interrupting devices, are addressed in Table 3 with reduced maintenance activities.

While it is easy to associate protective relays to multiple levels of monitoring, it is also true that most of the components that can make up a Protection System can also have technological advancements that place them into higher levels of monitoring.

To use the Maintenance Activities and Intervals Tables from PRC-005-4:

- First find the Table associated with your component. The tables are arranged in the order of mention in the definition of Protection System;
    - Table 1-1 is for protective relays,
    - Table 1-2 is for the associated communications systems,
    - Table 1-3 is for current and voltage sensing devices,
    - Table 1-4 is for station dc supply and
    - Table 1-5 is for control circuits.
    - Table 2, is for alarms; this was broken out to simplify the other tables.
    - Table 3 is for components which make-up distributed UFLS and UVLS Systems.
    - Table 4 is for Automatic Reclosing.
    - Table 5 is for Sudden Pressure Relaying.
- Next look within that table for your device and its degree of monitoring. The Tables have different hands-on maintenance activities prescribed depending upon the degree to which you monitor your equipment. Find the maintenance activity that applies to the monitoring level that you have on your piece of equipment.
- This Maintenance activity is the minimum maintenance activity that must be documented.
- If your Performance-Based Maintenance (PBM) plan requires <u>more activities,</u> then you must perform and document to this higher standard. (Note that this does not apply unless you utilize PBM.)
- After the maintenance activity is known, check the maximum maintenance interval; this time is the maximum time allowed between hands-on maintenance activity cycles of this component.
- If your Performance-Based Maintenance plan requires activities <u>more often</u> than the Tables maximum, then you must perform and document those activities to your more stringent standard. (Note that this does not apply unless you utilize PBM.)
- Any given component of a Protection System can be determined to have a degree of monitoring that may be different from another component within that same Protection System. For example, in a given Protection System it is possible for an entity to have a monitored protective relay and an unmonitored associated communications system; this combination would require hands-on maintenance activity on the relay at least once every 12 years and attention paid to the communications system as often as every four months.
- An entity does not have to utilize the extended time intervals made available by this use of condition-based monitoring. An easy choice to make is to simply utilize the unmonitored level of maintenance made available in each of the Tables. While the maintenance activities resulting from this choice would require more maintenance man-hours, the maintenance requirements may be simpler to document and the resulting maintenance plans may be easier to create.

For each Protection System Component, Table 1 shows maximum allowable testing intervals for the various degrees of monitoring. For each Automatic Reclosing Component, Table 4 shows maximum allowable testing intervals for the various degrees of monitoring. These degrees of monitoring, or levels, range from the legacy unmonitored through a system that is more comprehensively monitored.

It has been noted here that an entity may have a PSMP that is more stringent than PRC-005-4. There may be any number of reasons that an entity chooses a more stringent plan than the minimums prescribed within PRC-005-4, most notable of which is an entity using performance based maintenance methodology.

If an entity has a Performance-Based Maintenance program, then that plan must be followed, even if the plan proves to be more stringent than the minimums laid out in the Tables.

If an entity has a Time-Based Maintenance program and the PSMP is more stringent than PRC-005-4, they will only be audited in accordance with the standard (minimum maintenance activities and maximum maintenance intervals prescribed within Tables 1-1 through 1-5, Table 2, Table 3, Table 4-1 through 4-2, and Table 5).

8.1.2 Additional Notes for Tables 1-1 through 1-5, Table 3, and Table 4

1. For electromechanical relays, adjustment is required to bring measurement accuracy within the tolerance needed by the asset owner. Microprocessor relays with no remote monitoring of alarm contacts, etc., are unmonitored relays and need to be verified within the Table interval as other unmonitored relays but may be verified as functional by means other than testing by simulated inputs.

2. Microprocessor relays typically are specified by manufacturers as not requiring calibration, but acceptable measurement of power system input values must be verified (verification of the Analog to Digital [A/D] converters) within the Table intervals. The integrity of the digital inputs and outputs that are used as protective functions must be verified within the Table intervals.

3. Any Phasor Measurement Unit (PMU) function whose output is used in a Protection System or RAS (as opposed to a monitoring task) must be verified as a component in a Protection System.

4. In addition to verifying the circuitry that supplies dc to the Protection System, the owner must maintain the station dc supply. The most widespread station dc supply is the station battery and charger. Unlike most Protection System components, physical inspection of station batteries for signs of component failure, reduced performance, and degradation are required to ensure that the station battery is reliable enough to deliver dc power when required. IEEE Standards 450, 1188, and 1106 for vented lead-acid, valve-regulated lead-acid, and nickel-cadmium batteries, respectively (which are the most commonly used substation batteries on the NERC BES) have been developed as an important reference source of maintenance recommendations. The Protection System owner might want to follow the guidelines in the applicable IEEE recommended practices for battery maintenance and testing, especially if the battery in question is used for application requirements in addition to the protection and control demands covered under this standard. However, the Standard Drafting Team has tailored the battery maintenance and

testing guidelines in PRC-005-4 for the Protection System owner which are application specific for the BES Facilities. While the IEEE recommendations are all encompassing, PRC-005-4 is a more economical approach while addressing the reliability requirements of the BES.

5. Aggregated small entities might distribute the testing of the population of UFLS/UVLS systems, and large entities will usually maintain a portion of these systems in any given year. Additionally, if relatively small quantities of such systems do not perform properly, it will not affect the integrity of the overall program. Thus, these distributed systems have decreased requirements as compared to other Protection Systems.

6. Voltage & current sensing device circuit input connections to the Protection System relays can be verified by (but not limited to) comparison of measured values on live circuits or by using test currents and voltages on equipment out of service for maintenance. The verification process can be automated or manual. The values should be verified to be as expected (phase value and phase relationships are both equally important to verify).

7. "End-to-end test," as used in this Supplementary Reference, is any testing procedure that creates a remote input to the local communications-assisted trip scheme. While this can be interpreted as a GPS-type functional test, it is not limited to testing via GPS. Any remote scheme manipulation that can cause action at the local trip path can be used to functionally-test the dc control circuitry. A documented Real-time trip of any given trip path is acceptable in lieu of a functional trip test. It is possible, with sufficient monitoring, to be able to verify each and every parallel trip path that participated in any given dc control circuit trip. Or another possible solution is that a single trip path from a single monitored relay can be verified to be the trip path that successfully tripped during a Real-time operation. The variations are only limited by the degree of engineering and monitoring that an entity desires to pursue.

8. A/D verification may use relay front panel value displays, or values gathered via data communications. Groupings of other measurements (such as vector summation of bus feeder currents) can be used for comparison if calibration requirements assure acceptable measurement of power system input values.

9. Notes 1-8 attempt to describe some testing activities; they do not represent the only methods to achieve these activities, but rather some possible methods. Technological advances, ingenuity and/or industry accepted techniques can all be used to satisfy maintenance activity requirements; the standard is technology- and method-neutral in most cases.

8.1.3 Frequently Asked Questions:

What is meant by "Verify that settings are as specified" maintenance activity in Table 1-1?

Verification of settings is an activity directed mostly towards microprocessor- based relays. For relay maintenance departments that choose to test microprocessor-based relays in the same manner as electromechanical relays are tested, the testing process sometimes requires that some specific functions be disabled. Later tests might enable the functions previously disabled, but perhaps still other functions or logic statements were then masked out. It is imperative that, when the relay is placed into service, the settings in the relay be the settings that were intended to be in that relay or as the standard states "…settings are as specified."

Many of the microprocessor- based relays available today have software tools which provide this functionality and generate reports for this purpose.

For evidence or documentation of this requirement, a simple recorded acknowledgement that the settings were checked to be as specified is sufficient.

The drafting team was careful not to require "…that the relay settings be correct…" because it was believed that this might then place a burden of proof that the specified settings would result in the correct intended operation of the interrupting device. While that is a noble intention, the measurable proof of such a requirement is immense. The intent is that settings of the component be as specified at the conclusion of maintenance activities, whether those settings may have "drifted" since the prior maintenance or whether changes were made as part of the testing process.

Are electromechanical relays included in the "Verify that settings are as specified" maintenance activity in Table 1-1?

Verification of settings is an activity directed towards the application of protection related functions of microprocessor based relays. Electromechanical relays require calibration verification by voltage and/or current injection; and, thus, the settings are verified during calibration activity. In the example of a time-overcurrent relay, a minor deviation in time dial, versus the settings, may be acceptable, as long as the relay calibration is within accepted tolerances at the injected current amplitudes. A major deviation may require further investigation, as it could indicate a problem with the relay or an incorrect relay style for the application.

The verification of phase current and voltage measurements by comparison to other quantities seems reasonable. How, though, can I verify residual or neutral currents, or 3V0 voltages, by comparison, when my system is closely balanced?

Since these inputs are verified at commissioning, maintenance verification requires ensuring that phase quantities are as expected and that 3IO and 3VO quantities appear equal to or close to 0.

These quantities also may be verified by use of oscillographic records for connected microprocessor relays as recorded during system Disturbances. Such records may compare to similar values recorded at other locations by other microprocessor relays for the same event, or compared to expected values (from short circuit studies) for known Fault locations.

What does this Standard require for testing an auxiliary tripping relay?

Table 1 and Table 3 requires that a trip test must verify that the auxiliary tripping relay(s) and/or lockout relay(s) which are directly in a trip path from the protective relay to the interrupting device trip coil operate(s) electrically. Auxiliary outputs not in a trip path (i.e. annunciation or DME input) are not required, by this standard, to be checked.

Do I have to perform a full end-to-end test of a Remedial Action Schemes?

No. All portions of the -RAS need to be maintained, and the portions must overlap, but the overall RAS does not need to have a single end-to-end test. In other words it may be tested in piecemeal fashion provided all of the pieces are verified.

What about RAS interfaces between different entities or owners?

As in all of the Protection System requirements, RAS segments can be tested individually, thus minimizing the need to accommodate complex maintenance schedules.

What do I have to do if I am using a phasor measurement unit (PMU) as part of a Protection System or Remedial Action Schemes?

Any Phasor Measurement Unit (PMU) function whose output is used in a Protection System or Remedial Action Schemes (as opposed to a monitoring task) must be verified as a component in a Protection System.

How do I maintain a Remedial Action Schemes or relay sensing for non-distributed UFLS or UVLS Systems?

Since components of the RAS, UFLS and UVLS are the same types of components as those in Protection Systems, then these components should be maintained like similar components used for other Protection System functions. In many cases the devices for RAS, UFLS and UVLS are also used for other protective functions. The same maintenance activities apply with the exception that distributed systems (UFLS and UVLS) have fewer dc supply and control circuitry maintenance activity requirements.

For the testing of the output action, verification may be by breaker tripping, but may be verified in overlapping segments. For example, an RAS that trips a remote circuit breaker might be tested by testing the various parts of the scheme in overlapping segments. Another method is to document the Real-time tripping of an RAS scheme should that occur. Forced trip tests of circuit breakers (etc.) that are a part of distributed UFLS or UVLS schemes are not required.

The established maximum allowable intervals do not align well with the scheduled outages for my power plant. Can I extend the maintenance to the next scheduled outage following the established maximum interval?

No. You must complete your maintenance within the established maximum allowable intervals in order to be compliant. You will need to schedule your maintenance during available outages to complete your maintenance as required, even if it means that you may do protective relay maintenance more frequently than the maximum allowable intervals. The maintenance intervals were selected with typical plant outages, among other things, in mind.

If I am unable to complete the maintenance, as required, due to a major natural disaster (hurricane, earthquake, etc.), how will this affect my compliance with this standard?

The Sanction Guidelines of the North American Electric Reliability Corporation, effective January 15, 2008, provides that the Compliance Monitor will consider extenuating circumstances when considering any sanctions.

What if my observed testing results show a high incidence of out-of-tolerance relays; or, even worse, I am experiencing numerous relay Misoperations due to the relays being out-of-tolerance?

The established maximum time intervals are mandatory only as a not-to-exceed limitation. The establishment of a maximum is measurable. But any entity can choose to test some or all of their Protection System components more frequently (or to express it differently, exceed the minimum requirements of the standard). Particularly if you find that the maximum intervals in the standard do not achieve your expected level of performance, it is understandable that you would maintain the related equipment more frequently. A high incidence of relay Misoperations is in no one's best interest.

We believe that the four-month interval between inspections is unneccessary. Why can we not perform these inspections twice per year?

The Standard Drafting Team, through the comment process, has discovered that routine monthly inspections are not the norm. To align routine station inspections with other important inspections, the four-month interval was chosen. In lieu of station visits, many activities can be accomplished with automated monitoring and alarming.

Our maintenance plan calls for us to perform routine protective relay tests every 3 years. If we are unable to achieve this schedule, but we are able to complete the procedures in less than the maximum time interval ,then are we in or out of compliance?

According to R3, if you have a time-based maintenance program, then you will be in violation of the standard only if you exceed the maximum maintenance intervals prescribed in the Tables. According to R4, if your device in question is part of a Performance-Based Maintenance program, then you will be in violation of the standard if you fail to meet your PSMP, even if you do not exceed the maximum maintenance intervals prescribed in the Tables. The intervals in the Tables are associated with TBM and CBM; Attachment A is associated with PBM.

Please provide a sample list of devices or systems that must be verified in a generator, generator step-up transformer, generator connected station service or generator connected excitation transformer to meet the requirements of this maintenance standard.

Examples of typical devices and systems that may directly trip the generator, or trip through a lockout relay, may include, but are not necessarily limited to:

- Fault protective functions, including distance functions, voltage-restrained overcurrent functions, or voltage-controlled overcurrent functions
- Loss-of-field relays
- Volts-per-hertz relays
- Negative sequence overcurrent relays
- Over voltage and under voltage protection relays
- Stator-ground relays
- Communications-based Protection Systems such as transfer-trip systems
- Generator differential relays
- Reverse power relays
- Frequency relays
- Out-of-step relays
- Inadvertent energization protection

- Breaker failure protection

For generator step-up, generator-connected station service transformers, or generator connected excitation transformers, operation of any of the following associated protective relays frequently would result in a trip of the generating unit; and, as such, would be included in the program:

- Transformer differential relays
- Neutral overcurrent relay
- Phase overcurrent relays

Relays which trip breakers serving station auxiliary Loads such as pumps, fans, or fuel handling equipment, etc., need not be included in the program, even if the loss of the those Loads could result in a trip of the generating unit. Furthermore, relays which provide protection to secondary unit substation (SUS) or low switchgear transformers and relays protecting other downstream plant electrical distribution system components are not included in the scope of this program, even if a trip of these devices might eventually result in a trip of the generating unit. For example, a thermal overcurrent trip on the motor of a coal-conveyor belt could eventually lead to the tripping of the generator, but it does not cause the trip.

In the case where a plant does not have a generator connected station service transformer such that it is normally fed from a system connected station service transformer, is it still the drafting team's intent to exclude the Protection Systems for these system connected auxiliary transformers from scope even when the loss of the normal (system connected) station service transformer will result in a trip of a BES generating Facility?

The SDT does not intend that the system-connected station service transformers be included in the Applicability. The generator-connected station service transformers and generator connected excitation transformers are often connected to the generator bus directly without an interposing breaker; thus, the Protection Systems on these transformers will trip the generator as discussed in 4.2.5.1.

What is meant by "verify operation of the relay inputs and outputs that are essential to proper functioning of the Protection System?"

Any input or output (of the relay) that "affects the tripping" of the breaker is included in the scope of I/O of the relay to be verified. By "affects the tripping," one needs to realize that sometimes there are more inputs and outputs than simply the output to the trip coil. Many important protective functions include things like breaker fail initiation, zone timer initiation and sometimes even 52a/b contact inputs are needed for a protective relay to correctly operate.

Each input should be "picked up" or "turned on and off" and verified as changing state by the microprocessor of the relay. Each output should be "operated" or "closed and opened" from the microprocessor of the relay and the output should be verified to change state on the output terminals of the relay. One possible method of testing inputs of these relays is to "jumper" the needed dc voltage to the input and verify that the relay registered the change of state.

Electromechanical lock-out relays (86) (used to convey the tripping current to the trip coils) need to be electrically operated to prove the capability of the device to change state. These tests need to be accomplished at least every six years, unless PBM methodology is applied.

The contacts on the 86 or auxiliary tripping relays (94) that change state to pass on the trip current to a breaker trip coil need only be checked every 12 years with the control circuitry.

What is the difference between a distributed UFLS/UVLS and a non-distributed UFLS/UVLS scheme?

A distributed UFLS or UVLS scheme contains individual relays which make independent Load shed decisions based on applied settings and localized voltage and/or current inputs. A distributed scheme may involve an enable/disable contact in the scheme and still be considered a distributed scheme. A non-distributed UFLS or UVLS scheme involves a system where there is some type of centralized measurement and Load shed decision being made. A non-distributed UFLS/UVLS scheme is considered similar to an RAS scheme and falls under Table 1 for maintenance activities and intervals.

8.2 Retention of Records

PRC-005-1 describes a reporting or auditing cycle of one year and retention of records for three years. However, with a three-year retention cycle, the records of verification for a Protection System might be discarded before the next verification, leaving no record of what was done if a Misoperation or failure is to be analyzed.

PRC-005-4 corrects this by requiring:

The Transmission Owner, Generator Owner, and Distribution Provider shall each keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

For Requirement R1, the Transmission Owner, Generator Owner, and Distribution Provider shall each keep its current dated Protection System Maintenance Program, as well as any superseded versions since the preceding compliance audit, including the documentation that specifies the type of maintenance program applied for each Protection System, Automatic Reclosing, or Sudden Pressure Relaying Component Type.

For Requirement R2, Requirement R3, and Requirement R4, in cases where the interval of the maintenance activity is longer than the audit cycle, the Transmission Owner, Generator Owner, and Distribution Provider shall each keep documentation of the most recent performance of that maintenance activity for the Protection System, Automatic Reclosing, or Sudden Pressure Relaying Component. In cases where the interval of the maintenance activity is shorter than the audit cycle, documentation of all performances (in accordance with the tables) of that maintenance activity for the Protection System, Automatic Reclosing, or Sudden Pressure Relaying Component since the previous scheduled audit date shall be retained.

For Requirement R5 the Transmission Owner, Generator Owner, and Distribution Provider shall each keep documentation of Unresolved Maintenance Issues identified by the entity since the last audit, including all that were resolved since the last audit.

This requirement assures that the documentation shows that the interval between maintenance cycles correctly meets the maintenance interval limits. The requirement is actually alerting the industry to documentation requirements already implemented by audit teams. Evidence of compliance bookending the interval shows interval accomplished instead of proving only your planned interval.

The SDT is aware that, in some cases, the retention period could be relatively long. But, the retention of documents simply helps to demonstrate compliance.

8.2.1 Frequently Asked Questions:

Please clarify the data retention requirements.

The data retention requirements are intended to allow the availability of maintenance records to demonstrate that the time intervals in your maintenance plan were upheld.

Maximum Maintenance Interval	Data Retention Period
4 Months, 6 Months,18 Months, or 3 Years	All activities since previous audit
6 Years	All activities since previous audit(assuming a 6 year audit cycle) or most recent performance(assuming 3 year audit cycle), whichever is longer
12 Year	All activities from the most recent performance

If an entity prefers to utilize Performance-Based Maintenance, then statistical data may well be retained for extended periods to assist with future adjustments in time intervals.

If an equipment item is replaced, then the entity can restart the maintenance-time-interval-clock if desired; however, the replacement of equipment does not remove any documentation requirements that would have been required to verify compliance with time-interval requirements. In other words, do not discard maintenance data that goes to verify your work.

The retention of documentation for new and/or replaced equipment is all about proving that the maintenance intervals had been in compliance. For example, a long-range plan of upgrades might lead an entity to ignore required maintenance; retaining the evidence of prior maintenance that existed before any retirements and upgrades proves compliance with the standard.

What does this Maintenance Standard say about commissioning? Is it necessary to have documentation in your maintenance history of the completion of commission testing?

This standard does not establish requirements for commission testing. Commission testing includes all testing activities necessary to conclude that a Facility has been built in accordance with design. While a thorough commission testing program would include, either directly or indirectly, the verification of all those Protection System attributes addressed by the maintenance activities specified in the Tables of PRC-005-4, verification of the adequacy of initial installation necessitates the performance of testing and inspections that go well beyond these routine maintenance activities. For example, commission testing might set baselines for future tests; perform acceptance tests and/or warranty tests; utilize testing methods that are not generally done routinely like staged-Fault-tests.

However, many of the Protection System attributes which are verified during commission testing are not subject to age related or service related degradation, and need not be re-verified within an ongoing maintenance program. Example – it is not necessary to re-verify correct terminal strip wiring on an ongoing basis.

PRC-005-4 assumes that thorough commission testing was performed prior to a Protection System being placed in service. PRC-005-4 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.

It should be noted that commission testing frequently is performed by a different organization than that which is responsible for the ongoing maintenance of the Protection System. Furthermore, the commission testing activities will not necessarily correlate directly with the maintenance activities required by the standard. As such, it is very likely that commission testing records will deviate significantly from maintenance records in both form and content; and, therefore, it is not necessary to maintain commission testing records within the maintenance program documentation.

Notwithstanding the differences in records, an entity would be wise to retain commissioning records to show a maintenance start date. (See below). An entity that requires that their commissioning tests have, at a minimum, the requirements of PRC-005-4 would help that entity prove time interval maximums by setting the initial time clock.

How do you determine the initial due date for maintenance?

The initial due date for maintenance should be based upon when a Protection System was tested. Alternatively, an entity may choose to use the date of completion of the commission testing of the Protection System component and the system was placed into service as the starting point in determining its first maintenance due dates. Whichever method is chosen, for newly installed Protection Systems the components should not be placed into service until minimum maintenance activities have taken place.

It is conceivable that there can be a (substantial) difference in time between the date of testing, as compared to the date placed into service. The use of the “Calendar Year” language can help determine the next due date without too much concern about being non-compliant for missing test dates by a small amount (provided your dates are not already at the end of a year). However, if there is a substantial amount of time difference between testing and in-service dates, then the testing date should be followed because it is the degradation of components that is the concern. While accuracy fluctuations may decrease when components are not energized, there are cases when degradation can take place, even though the device is not energized. Minimizing the time between commissioning tests and in-service dates will help.

If I miss two battery inspections four times out of 100 Protection System components on my transmission system, does that count as 2% or 8% when counting Violation Severity Level (VSL) for R3?

The entity failed to complete its scheduled program on two of its 100 Protection System components, which would equate to 2% for application to the VSL Table for Requirement R3.

This VSL is written to compare missed components to total components. In this case two components out of 100 were missed, or 2%.

How do I achieve a "grace period" without being out of compliance?

The objective here is to create a time extension within your own PSMP that still does not violate the maximum time intervals stated in the standard. Remember that the maximum time intervals listed in the Tables cannot be extended.

For the purposes of this example, concentrating on just unmonitored protective relays – Table 1-1 specifies a maximum time interval (between the mandated maintenance activities) of six calendar years. Your plan must ensure that your unmonitored relays are tested at least once every six calendar years. You could, within your PSMP, require that your unmonitored relays be tested every four calendar years, with a maximum allowable time extension of 18 calendar months. This allows an entity to have deadlines set for the auto-generation of work orders, but still has the flexibility in scheduling complex work schedules. This also allows for that 18 calendar months to act as a buffer, in effect a grace period within your PSMP, in the event of unforeseen events. You will note that this example of a maintenance plan interval has a planned time of four years; it also has a built-in time extension allowed within the PSMP, and yet does not exceed the maximum time interval allowed by the standard. So while there are no time extensions allowed beyond the standard, an entity can still have substantial flexibility to maintain their Protection System components.

8.3 Basis for Table 1 Intervals

When developing the original *Protection System Maintenance – A Technical Reference* in 2007, the SPCTF collected all available data from Regional Entities (REs) on time intervals recommended for maintenance and test programs. The recommendations vary widely in categorization of relays, defined maintenance actions, and time intervals, precluding development of intervals by averaging. The SPCTF also reviewed the 2005 Report [2] of the IEEE Power System Relaying Committee Working Group I-17 (Transmission Relay System Performance Comparison). Review of the I-17 report shows data from a small number of utilities, with no company identification or means of investigating the significance of particular results.

To develop a solid current base of practice, the SPCTF surveyed its members regarding their maintenance intervals for electromechanical and microprocessor relays, and asked the members to also provide definitively-known data for other entities. The survey represented 470 GW of peak Load, or 4% of the NERC peak Load. Maintenance interval averages were compiled by weighting reported intervals according to the size (based on peak Load) of the reporting utility. Thus, the averages more accurately represent practices for the large populations of Protection Systems used across the NERC regions.

The results of this survey with weighted averaging indicate maintenance intervals of five years for electromechanical or solid state relays, and seven years for unmonitored microprocessor relays.

A number of utilities have extended maintenance intervals for microprocessor relays beyond seven years, based on favorable experience with the particular products they have installed. To provide a technical basis for such extension, the SPCTF authors developed a recommendation of 10 years using the Markov modeling approach from [1], as summarized in Section 8.4. The results of this modeling depend on the completeness of self-testing or monitoring. Accordingly, this extended interval is allowed by Table 1, only when such relays are monitored as specified in the attributes of monitoring contained in Tables 1-1 through 1-5 and Table 2. Monitoring is capable of reporting Protection System health issues that are likely to affect performance within the 10 year time interval between verifications.

It is important to note that, according to modeling results, Protection System availability barely changes as the maintenance interval is varied below the 10-year mark. Thus, reducing the maintenance interval does not improve Protection System availability. With the assumptions of the model regarding how maintenance is carried out, reducing the maintenance interval actually degrades Protection System availability.

8.4 Basis for Extended Maintenance Intervals for Microprocessor Relays

Table 1 allows maximum verification intervals that are extended based on monitoring level. The industry has experience with self-monitoring microprocessor relays that leads to the Table 1 value for a monitored relay, as explained in Section 8.3. To develop a basis for the maximum interval for monitored relays in their *Protection System Maintenance – A Technical Reference*, the SPCTF used the methodology of Reference [1], which specifically addresses optimum routine maintenance intervals. The Markov modeling approach of [1] is judged to be valid for the design and typical failure modes of microprocessor relays.

The SPCTF authors ran test cases of the Markov model to calculate two key probability measures:

- Relay Unavailability - the probability that the relay is out of service due to failure or maintenance activity while the power system Element to be protected is in service.
- Abnormal Unavailability - the probability that the relay is out of service due to failure or maintenance activity when a Fault occurs, leading to failure to operate for the Fault.

The parameter in the Markov model that defines self-monitoring capability is ST (for self-test). ST = 0 if there is no self-monitoring; ST = 1 for full monitoring. Practical ST values are estimated to range from .75 to .95. The SPCTF simulation runs used constants in the Markov model that were the same as those used in [1] with the following exceptions:

Sn, Normal tripping operations per hour = 21600 (reciprocal of normal Fault clearing time of 10 cycles)

Sb, Backup tripping operations per hour = 4320 (reciprocal of backup Fault clearing time of 50 cycles)

Rc, Protected component repairs per hour = 0.125 (8 hours to restore the power system)

Rt, Relay routine tests per hour = 0.125 (8 hours to test a Protection System)

Rr, Relay repairs per hour = 0.08333 (12 hours to complete a Protection System repair after failure)

Experimental runs of the model showed low sensitivity of optimum maintenance interval to these parameter adjustments.

The resulting curves for relay unavailability and abnormal unavailability versus maintenance interval showed a broad minimum (optimum maintenance interval) in the vicinity of 10 years – the curve is flat, with no significant change in either unavailability value over the range of 9, 10, or 11 years. This was true even for a relay mean time between Failures (MTBF) of 50 years, much lower than MTBF values typically published for these relays. Also, the Markov modeling indicates that both the relay unavailability and abnormal unavailability actually become higher with more frequent testing. This shows that the time spent on these more frequent tests yields no failure discoveries that approach the negative impact of removing the relays from service and running the tests.

The PSMT SDT discussed the practical need for "time-interval extensions" or "grace periods" to allow for scheduling problems that resulted from any number of business contingencies. The time interval discussions also focused on the need to reflect industry norms surrounding Generator outage frequencies. Finally, it was again noted that FERC Order 693 demanded maximum time intervals. "Maximum time intervals" by their very term negates any "time-interval extension" or "grace periods." To recognize the need to follow industry norms on Generator outage frequencies and accommodate a form of time-interval extension, while still following FERC Order 693, the Standard Drafting Team arrived at a six-year interval for the electromechanical relay, instead of the five-year interval arrived at by the SPCTF. The PSMT SDT has followed the FERC directive for a *maximum* time interval and has determined that no extensions will be allowed. Six years has been set for the maximum time interval between manual maintenance activities. This maximum time interval also works well for maintenance cycles that have been in use in generator plants for decades.

For monitored relays, the PSMT SDT notes that the SPCTF called for 10 years as the interval between maintenance activities. This 10-year interval was chosen, even though there was "…no significant change in unavailability value over the range of 9, 10, or 11 years. This was true even for a relay Mean Time between Failures (MTBF) of 50 years…" The Standard Drafting Team again sought to align maintenance activities with known successful practices and outage schedules. The Standard does not allow extensions on any component of the Protection System; thus, the maximum allowed interval for these components has been set to 12 years. Twelve years also fits well into the traditional maintenance cycles of both substations and generator plants.

Also of note is the Table's use of the term "Calendar" in the column for "Maximum Maintenance Interval." The PSMT SDT deemed it necessary to include the term "Calendar" to facilitate annual maintenance planning, scheduling and implementation. This need is the result of known occurrences of system requirements that could cause maintenance schedules to be missed by a few days or weeks. The PSMT SDT chose the term "Calendar" to preclude the need to have schedules be met to the day. An electromechanical protective relay that is maintained in year number one need not be revisited until six years later (year number seven). For example, a relay was maintained April 10, 2008; maintenance would need to be completed no later than December 31, 2014.

Though not a requirement of this standard, to stay in line with many Compliance Enforcement Agencies audit processes an entity should define, within their own PSMP, the entity's use of terms like annual, calendar year, etc. Then, once this is within the PSMP, the entity should abide by their chosen language.

9. Performance-Based Maintenance Process

In lieu of using the Table 1 intervals, a Performance-Based Maintenance process may be used to establish maintenance intervals (*PRC-005 Attachment A Criteria for a Performance-Based Protection System Maintenance Program*). A Performance-Based Maintenance process may justify longer maintenance intervals, or require shorter intervals relative to Table 1. In order to use a Performance-Based Maintenance process, the documented maintenance program must include records of repairs, adjustments, and corrections to covered Protection Systems in order to provide historical justification for intervals, other than those established in Table 1. Furthermore, the asset owner must regularly analyze these records of corrective actions to develop a ranking of causes. Recurrent problems are to be highlighted, and remedial action plans are to be documented to mitigate or eliminate recurrent problems.

Entities with Performance-Based Maintenance track performance of Protection Systems, demonstrate how they analyze findings of performance failures and aberrations, and implement continuous improvement actions. Since no maintenance program can ever guarantee that no malfunction can possibly occur, documentation of a Performance-Based Maintenance program would serve the utility well in explaining to regulators and the public a Misoperation leading to a major System outage event.

A Performance-Based Maintenance program requires auditing processes like those included in widely used industrial quality systems (such as ***ISO 9001-2000, Quality Management Systems — Requirements;*** or applicable parts of the NIST Baldridge National Quality Program). The audits periodically evaluate:

- The completeness of the documented maintenance process
- Organizational knowledge of and adherence to the process
- Performance metrics and documentation of results
- Remediation of issues
- Demonstration of continuous improvement.

In order to opt into a Performance-Based Maintenance (PBM) program, the asset owner must first sort the various Components into population segments. Any population segment must be comprised of at least 60 individual units; if any asset owner opts for PBM, but does not own 60 units to comprise a population, then that asset owner may combine data from other asset owners until the needed 60 units is aggregated. Each population segment must be composed of a grouping of Components of a consistent design standard or particular model or type from a single manufacturer and subjected to similar environmental factors. For example: One segment cannot be comprised of both GE & Westinghouse electro-mechanical lock-out relays; likewise, one segment cannot be comprised of 60 GE lock-out relays, 30 of which are in a dirty environment, and the remaining 30 from a clean environment. This PBM process cannot be applied to batteries, but can be applied to all other Components, including (but not limited to) specific battery chargers, instrument transformers, trip coils and/or control circuitry (etc.).

9.1 Minimum Sample Size

Large Sample Size

An assumption that needs to be made when choosing a sample size is "the sampling distribution of the sample mean can be approximated by a normal probability distribution." The Central Limit Theorem states: "In selecting simple random samples of size *n* from a population, the sampling distribution of the sample mean *x* can be approximated by a normal probability distribution as the sample size becomes large." (Essentials of Statistics for Business and Economics, Anderson, Sweeney, Williams, 2003.)

To use the Central Limit Theorem in statistics, the population size should be large. The references below are supplied to help define what is large.

> "… whenever we are using a large simple random sample (rule of thumb: n>=30), the central limit theorem enables us to conclude that the sampling distribution of the sample mean can be approximated by a normal distribution." (Essentials of Statistics for Business and Economics, Anderson, Sweeney, Williams, 2003.)
>
> "If samples of size n, when n>=30, are drawn from any population with a mean *u* and a standard deviation σ, the sampling distribution of sample means approximates a normal distribution. The greater the sample size, the better the approximation." (Elementary Statistics - Picturing the World, Larson, Farber, 2003.)
>
> "The sample size is large (generally n>=30)… (Introduction to Statistics and Data Analysis - Second Edition, Peck, Olson, Devore, 2005.)
>
> "… the normal is often used as an approximation to the *t* distribution in a test of a null hypothesis about the mean of a normally distributed population when the population variance is estimated from a relatively large sample. A sample size exceeding 30 is often given as a minimal size in this connection." (Statistical Analysis for Business Decisions, Peters, Summers, 1968.)

Error of Distribution Formula

Beyond the large sample size discussion above, a sample size requirement can be estimated using the bound on the Error of Distribution Formula when the expected result is of a "Pass/Fail" format and will be between 0 and 1.0.

The Error of Distribution Formula is:

$$B = z\sqrt{\frac{\pi(1-\pi)}{n}}$$

Where:

B = bound on the error of distribution (allowable error)

z = standard error

π = expected failure rate

n = sample size required

Solving for n provides:

$$n = \pi(1-\pi)\left(\frac{z}{B}\right)^2$$

Minimum Population Size to use Performance-Based Program

One entity's population of components should be large enough to represent a sizeable sample of a vendor's overall population of manufactured devices. For this reason, the following assumptions are made:

B = 5%

z = 1.96 (This equates to a 95% confidence level)

π = 4%

Using the equation above, n=59.0.

Minimum Sample Size to evaluate Performance-Based Program

The number of components that should be included in a sample size for evaluation of the appropriate testing interval can be smaller because a lower confidence level is acceptable since the sample testing is repeated or updated annually. For this reason, the following assumptions are made:

B = 5%

z = 1.44 (85% confidence level)

π = 4%

Using the equation above, n=31.8.

Recommendation

Based on the above discussion, a sample size should be at least 30 to allow use of the equation mentioned. Using this and the results of the equation, the following numbers are recommended (and required within the standard):

Minimum Population Size to use Performance-Based Maintenance Program = 60

Minimum Sample Size to evaluate Performance-Based Program = 30.

Once the population segment is defined, then maintenance must begin within the intervals as outlined for the device described in the Tables 1-1 through 1-5. Time intervals can be lengthened provided the last year's worth of components tested (or the last 30 units maintained, whichever is more) had fewer than 4% Countable Events. It is notable that 4% is specifically chosen because an entity with a small population (30 units) would have to adjust its time intervals between maintenance if more than one Countable Event was found to have occurred during the last analysis period. A smaller percentage would require that entity to adjust the time interval between maintenance activities if even one unit is found out of tolerance or causes a Misoperation.

The minimum number of units that can be tested in any given year is 5% of the population. Note that this 5% threshold sets a practical limitation on total length of time between intervals at 20 years.

If at any time the number of Countable Events equals or exceeds 4% of the last year's tested components (or the last 30 units maintained, whichever is more), then the time period between manual maintenance activities must be decreased. There is a time limit on reaching the decreased time at which the Countable Events is less than 4%; this must be attained within three years.

Performance-Based Program Evaluation Example

The 4% performance target was derived as a protection system performance target and was selected based on the drafting team's experience and studies performed by several utilities. This is not derived from the performance of discrete devices. Microprocessor relays and electromechanical relays have different performance levels. It is not appropriate to compare these performance levels to each other. The performance of the segment should be compared to the 4% performance criteria.

In consideration of the use of Performance Based Maintenance (PBM), the user should consider the effects of extended testing intervals and the established 4% failure rate. In the table shown below, the segment is 1000 units. As the testing interval (in years) increases, the number of units tested each year decreases. The number of countable events allowed is 4% of the tested units. Countable events are the failure of a Component requiring repair or replacement, any corrective actions performed during the maintenance test on the units within the testing segment (units per year), or any misoperation attributable to hardware failure or calibration failure found within the entire segment (1000 units) during the testing year.

Example: 1000 units in the segment with a testing interval of 8 years: The number of units tested each year will be 125 units. The total allowable countable events equals: 125 X .04 = 5. This number includes failure of a Component requiring repair or replacement, corrective issues found during testing, and the total number of misoperations (attributable to hardware or calibration failure within the testing year) associated with the entire segment of 1000 units.

Example: 1000 units in the segment with a testing interval of 16 years: The number of units tested each year will be 63 units. The total allowable countable events equals: 63 X .04 = 2.5.

As shown in the above examples, doubling the testing interval reduces the number of allowable events by half.

Total number of units in the segment	1000
Failure rate	4.00%

Testing Intervals (Years)	Units Per Year	Acceptable Number of Countable Events per year	Yearly Failure Rate Based on 1000 Units in Segment
1	1000.00	40.00	4.00%
2	500.00	20.00	2.00%
4	250.00	10.00	1.00%
6	166.67	6.67	0.67%
8	125.00	5.00	0.50%
10	100.00	4.00	0.40%
12	83.33	3.33	0.33%
14	71.43	2.86	0.29%
16	62.50	2.50	0.25%
18	55.56	2.22	0.22%
20	50.00	2.00	0.20%

Using the prior year's data, determine the maximum allowable maintenance interval for each Segment such that the Segment experiences Countable Events on no more than 4% of the Components within the Segment, for the greater of either the last 30 Components maintained or all Components maintained in the previous year.

Segment – Components of a consistent design standard, or a particular model or type from a single manufacturer that typically share other common elements. Consistent performance is expected across the entire population of a Segment. A Segment must contain at least sixty (60) individual Components.

Countable Event – A failure of a Component requiring repair or replacement, any condition discovered during the maintenance activities in Tables 1-1 through 1-5, Table 3, Table 4-1 through Table 4-2, and Table 5, which requires corrective action or a Protection System Misoperation attributed to hardware failure or calibration failure. Misoperations due to product design errors, software errors, relay settings different from specified settings, Protection System Component, Automatic Reclosing, or Sudden Pressure Relaying configuration or application errors are not included in Countable Events.

9.2 Frequently Asked Questions:

I'm a small entity and cannot aggregate a population of Protection System components to establish a segment required for a Performance-Based Protection System Maintenance Program. How can I utilize that opportunity?

Multiple asset owning entities may aggregate their individually owned populations of individual Protection System components to create a segment that crosses ownership boundaries. All entities participating in a joint program should have a single documented joint management

process, with consistent Protection System Maintenance Programs (practices, maintenance intervals and criteria), for which the multiple owners are individually responsible with respect to the requirements of the Standard. The requirements established for Performance-Based Maintenance must be met for the overall aggregated program on an ongoing basis.

The aggregated population should reflect all factors that affect consistent performance across the population, including any relevant environmental factors such as geography, power-plant vs. substation, and weather conditions.

Can an owner go straight to a Performance-Based Maintenance program schedule, if they have previously gathered records?

Yes. An owner can go to a Performance-Based Maintenance program immediately. The owner will need to comply with the requirements of a Performance-Based Maintenance program as listed in the Standard. Gaps in the data collected will not be allowed; therefore, if an owner finds that a gap exists such that they cannot prove that they have collected the data as required for a Performance-Based Maintenance program then they will need to wait until they can prove compliance.

When establishing a Performance-Based Maintenance program, can I use test data from the device manufacturer, or industry survey results, as results to help establish a basis for my Performance-Based intervals?

No, you must use actual in-service test data for the components in the segment.

What types of Misoperations or events are not considered Countable Events in the Performance-Based Protection System Maintenance (PBM) Program?

Countable Events are intended to address conditions that are attributed to hardware failure or calibration failure; that is, conditions that reflect deteriorating performance of the component. These conditions include any condition where the device previously worked properly, then, due to changes within the device, malfunctioned or degraded to the point that re-calibration (to within the entity's tolerance) was required.

For this purpose of tracking hardware issues, human errors resulting in Protection System Misoperations during system installation or maintenance activities are not considered Countable Events. Examples of excluded human errors include relay setting errors, design errors, wiring errors, inadvertent tripping of devices during testing or installation, and misapplication of Protection System components. Examples of misapplication of Protection System components include wrong CT or PT tap position, protective relay function misapplication, and components not specified correctly for their installation. Obviously, if one is setting up relevant data about hardware failures then human failures should be eliminated from the hardware performance analysis.

One example of human-error is not pertinent data might be in the area of testing "86" lock-out relays (LOR). "Entity A" has two types of LOR's type "X" and type "Y"; they want to move into a performance based maintenance interval. They have 1000 of each type, so the population variables are met. During electrical trip testing of all of their various schemes over the initial six-year interval they find zero type "X" failures, but human error led to tripping a BES Element 100 times; they find 100 type "Y" failures and had an additional 100 human-error caused tripping incidents. In this example the human-error caused Misoperations should not be used to judge the performance of either type of LOR. Analysis of the data might lead "Entity A" to change time intervals. Type "X" LOR can be placed into extended time interval testing because of its low failure

rate (zero failures) while Type “Y” would have to be tested more often than every 6 calendar years (100 failures divided by 1000 units exceeds the 4% tolerance level).

Certain types of Protection System component errors that cause Misoperations are not considered Countable Events. Examples of excluded component errors include device malfunctions that are correctable by firmware upgrades and design errors that do not impact protection function.

What are some examples of methods of correcting segment perfomance for Performance-Based Maintenance?

There are a number of methods that may be useful for correcting segment performance for mal-performing segments in a Performance-Based Maintenance system. Some examples are listed below.

- The maximum allowable interval, as established by the Performance-Based Maintenance system, can be decreased. This may, however, be slow to correct the performance of the segment.
- Identifiable sub-groups of components within the established segment, which have been identified to be the mal-performing portion of the segment, can be broken out as an independent segment for target action. Each resulting segment must satisfy the minimum population requirements for a Performance-Based Maintenance program in order to remain within the program.
- Targeted corrective actions can be taken to correct frequently occurring problems. An example would be replacement of capacitors within electromechanical distance relays if bad capacitors were determined to be the cause of the mal-performance.
- components within the mal-performing segment can be replaced with other components (electromechanical distance relays with microprocessor relays, for example) to remove the mal-performing segment.

If I find (and correct) a Unresolved Maintenance Issue as a result of a Misoperation investigation (Re: PRC-004), how does this affect my Performance-Based Maintenance program?

If you perform maintenance on a Protection System component for any reason (including as part of a PRC-004 required Misoperation investigation/corrective action), the actions performed can count as a maintenance activity provided the activities in the relevant Tables have been done, and, if you desire, “reset the clock” on everything you’ve done. In a Performance-Based Maintenance program, you also need to record the Unresolved Maintenance Issue as a Countable Event within the relevant component group segment and use it in the analysis to determine your correct Performance-Based Maintenance interval for that component group. Note that “resetting the clock” should not be construed as interfering with an entity’s routine testing schedule because the “clock-reset” would actually make for a decreased time interval by the time the next routine test schedule comes around.

For example a relay scheme, consisting of four relays, is tested on 1-1-11 and the PSMP has a time interval of 3 calendar years with an allowable extension of 1 calendar year. The relay would be due again for routine testing before the end of the year 2015. This mythical relay scheme has a Misoperation on 6-1-12 that points to one of the four relays as bad. Investigation proves a bad

relay and a new one is tested and installed in place of the original. This replacement relay actually could be retested before the end of the year 2016 (clock-reset) and not be out of compliance. This requires tracking maintenance by individual relays and is allowed. However, many companies schedule maintenance in other ways like by substation or by circuit breaker or by relay scheme. By these methods of tracking maintenance that "replaced relay" will be retested before the end of the year 2015. This is also acceptable. In no case was a particular relay tested beyond the PSMP of four years max, nor was the 6 year max of the Standard exceeded. The entity can reset the clock if they desire or the entity can continue with original schedules and, in effect, test even more frequently.

Why are batteries excluded from PBM? What about exclusion of batteries from condition based maintenance?

Batteries are the only element of a Protection System that is a perishable item with a shelf life. As a perishable item batteries require not only a constant float charge to maintain their freshness (charge), but periodic inspection to determine if there are problems associated with their aging process and testing to see if they are maintaining a charge or can still deliver their rated output as required.

Besides being perishable, a second unique feature of a battery that is unlike any other Protection System element is that a battery uses chemicals, metal alloys, plastics, welds, and bonds that must interact with each other to produce the constant dc source required for Protection Systems, undisturbed by ac system Disturbances.

No type of battery manufactured today for Protection System application is free from problems that can only be detected over time by inspection and test. These problems can arise from variances in the manufacturing process, chemicals and alloys used in the construction of the individual cells, quality of welds and bonds to connect the components, the plastics used to make batteries and the cell forming process for the individual battery cells.

Other problems that require periodic inspection and testing can result from transportation from the factory to the job site, length of time before a charge is put on the battery, the method of installation, the voltage level and duration of equalize charges, the float voltage level used, and the environment that the battery is installed in.

All of the above mentioned factors and several more not discussed here are beyond the control of the Functional Entities that want to use a Performance-Based Protection System Maintenance (PBM) program. These inherent variances in the aging process of a battery cell make establishment of a designated segment based on manufacturer and type of battery impossible.

The whole point of PBM is that if all variables are isolated then common aging and performance criteria would be the same. However, there are too many variables in the electrochemical process to completely isolate all of the performance-changing criteria.

Similarly, Functional Entities that want to establish a condition-based maintenance program using the highest levels of monitoring, resulting in the least amount of hands-on maintenance activity, cannot completely eliminate some periodic maintenance of the battery used in a station dc supply. Inspection of the battery is required on a Maximum Maintenance Interval listed in the tables due to the aging processes of station batteries. However, higher degrees of

monitoring of a battery can eliminate the requirement for some periodic testing and some inspections (see Table 1-4).

Please provide an example of the calculations involved in extending maintenance time intervals using PBM.

Entity has 1000 GE-HEA lock-out relays; this is greater than the minimum sample requirement of 60. They start out testing all of the relays within the prescribed Table requirements (6 year max) by testing the relays every 5 years. The entity's plan is to test 200 units per year; this is greater than the minimum sample size requirement of 30. For the sake of example only the following will show 6 failures per year, reality may well have different numbers of failures every year. PBM requires annual assessment of failures found per units tested. After the first year of tests the entity finds 6 failures in the 200 units tested. 6/200= 3% failure rate. This entity is now allowed to extend the maintenance interval if they choose. The entity chooses to extend the maintenance interval of this population segment out to 10 years. This represents a rate of 100 units tested per year; entity selects 100 units to be tested in the following year. After that year of testing these 100 units the entity again finds 6 failed units. 6/100= 6% failures. This entity has now exceeded the acceptable failure rate for these devices and must accelerate testing of all of the units at a higher rate such that the failure rate is found to be less than 4% per year; the entity has three years to get this failure rate down to 4% or less (per year). In response to the 6% failure rate, the entity decreases the testing interval to 8 years. This means that they will now test 125 units per year (1000/8). The entity has just two years left to get the test rate corrected.

After a year, they again find six failures out of the 125 units tested. 6/125= 5% failures. In response to the 5% failure rate, the entity decreases the testing interval to seven years. This means that they will now test 143 units per year (1000/7). The entity has just one year left to get the test rate corrected. After a year, they again find six failures out of the 143 units tested. 6/143= 4.2% failures.

(Note that the entity has tried five years and they were under the 4% limit and they tried seven years and they were over the 4% limit. They must be back at 4% failures or less in the next year so they might simply elect to go back to five years.)

Instead, in response to the 5% failure rate, the entity decreases the testing interval to six years. This means that they will now test 167 units per year (1000/6). After a year, they again find six failures out of the 167 units tested. 6/167= 3.6% failures. Entity found that they could maintain the failure rate at no more than 4% failures by maintaining the testing interval at six years or less. Entity chose six-year interval and effectively extended their TBM (five years) program by 20%.

A note of practicality is that an entity will probably be in better shape to lengthen the intervals between tests if the failure rate is less than 2%. But the requirements allow for annual adjustments, if the entity desires. As a matter of maintenance management, an ever-changing test rate (units tested/year) may be un-workable.

Note that the "5% of components" requirement effectively sets a practical limit of 20 year maximum PBM interval. Also of note is the "3 years" requirement; an entity might arbitrarily extend time intervals from six years to 20 years. In the event that an entity finds a failure rate greater than 4%, then the test rate must be accelerated such that within three years the failure rate must be brought back down to 4% or less.

Here is a table that demonstrates the values discussed:

Year #	Total Population (P)	Test Interval (I)	Units to be Tested (U= P/I)	# of Failures Found (F)	Failure Rate (=F/U)	Decision to Change Interval Yes or No	Interval Chosen
1	1000	5 yrs	200	6	3%	Yes	10 yrs
2	1000	10 yrs	100	6	6%	Yes	8 yrs
3	1000	8 yrs	125	6	5%	Yes	7 yrs
4	1000	7 yrs	143	6	4.2%	Yes	6 yrs
5	1000	6 yrs	167	6	3.6%	No	6 yrs

Please provide an example of the calculations involved in extending maintenance time intervals using PBM for control circuitry.

Note that the following example captures "Control Circuitry" as all of the trip paths associated with a particular trip coil of a circuit breaker. An entity is not restricted to this method of counting control circuits. Perhaps another method an entity would prefer would be to simply track every individual (parallel) trip path. Or perhaps another method would be to track all of the trip outputs from a specific (set) of relays protecting a specific element.

The designation of what constitutes a control circuit component is very dependent upon how an entity performs and tracks the testing of the control circuitry. Some entities test their control circuits on a breaker basis whereas others test their circuitry on a local zone of protection basis. Thus, entities are allowed the latitude to designate their own definitions of control circuit components. Another example of where the entity has some discretion on determining what constitutes a single component is the voltage and current sensing devices, where the entity may choose either to designate a full three-phase set of such devices or a single device as a single component.

And in Attachment A (PBM) the definition of Segment:

Segment –*Components of a consistent design standard, or a particular model or type from a single manufacturer that typically share other common elements. Consistent performance is expected across the entire population of a segment. A segment must contain at least sixty (60) individual components.*

Example:

Entity has 1,000 circuit breakers, all of which have two trip coils, for a total of 2,000 trip coils; if all circuitry was designed and built with a consistent (internal entity) standard, then this is greater than the minimum sample requirement of 60.

For the sake of further example, the following facts are given:

Half of all relay panels (500) were built 40 years ago by an outside contractor, consisted of asbestos wrapped 600V-insulation panel wiring, and the cables exiting the control house are THHN pulled in conduit direct to exactly half of all of the various circuit breakers. All of the relay panels and cable pulls were built with consistent standards and consistent performance standard expectations within the segment (which is greater than 60). Each relay panel has redundant microprocessor (MPC) relays (retrofitted); each MPC relay supplies an individual trip output to each of the two trip coils of the assigned circuit breaker.

Approximately 35 years ago, the entity developed their own internal construction crew and now builds all of their own relay panels from parts supplied from vendors that meet the entity's specifications, including SIS 600V insulation wiring and copper-sheathed cabling within the direct conduits to circuit breakers. The construction crew uses consistent standards in the construction. This newer segment of their control circuitry population is different than the original segment, consistent (standards, construction and performance expectations) within the new segment and constitutes the remainder of the entity's population (another 500 panels and the cabling to the remaining 500 circuit breakers). Each relay panel has redundant microprocessor (MPC) relays; each MPC relay supplies an individual trip output to each of the two trip coils of the assigned circuit breaker. Every trip path in this newer segment has a device that monitors the voltage

directly across the trip contacts of the MPC relays and alarms via RTU and SCADA to the operations control room. This monitoring device, when not in alarm, demonstrates continuity all the way through the trip coil, cabling and wiring back to the trip contacts of the MPC relay.

The entity is tracking 2,000 trip coils (each consisting of multiple trip paths) in each of these two segments. But half of all of the trip paths are monitored; therefore, the trip paths are continuously tested and the circuit will alarm when there is a failure. These alarms have to be verified every 12 years for correct operation.

The entity now has 1,000 trip coils (and associated trip paths) remaining that they have elected to count as control circuits. The entity has instituted a process that requires the verification of every trip path to each trip coil (one unit), including the electrical activation of the trip coil. (The entity notes that the trip coils will have to be tripped electrically more often than the trip path verification, and is taking care of this activity through other documentation of Real-time Fault operations.)

They start out testing all of the trip coil circuits within the prescribed Table requirements (12-year max) by testing the trip circuits every 10 years. The entity's plan is to test 100 units per year; this is greater than the minimum sample size requirement of 30. For the sake of example only, the following will show three failures per year; reality may well have different numbers of failures every year. PBM requires annual assessment of failures found per units tested. After the first year of tests, the entity finds three failures in the 100 units tested. 3/100= 3% failure rate.

This entity is now allowed to extend the maintenance interval, if they choose. The entity chooses to extend the maintenance interval of this population segment out to 20 years. This represents a rate of 50 units tested per year; entity selects 50 units to be tested in the following year. After that year of testing these 50 units, the entity again finds three failed units. 3/50= 6% failures.

This entity has now exceeded the acceptable failure rate for these devices and must accelerate testing of all of the units at a higher rate, such that the failure rate is found to be less than 4% per year; the entity has three years to get this failure rate down to 4% or less (per year).

In response to the 6% failure rate, the entity decreases the testing interval to 16 years. This means that they will now test 63 units per year (1000/16). The entity has just two years left to get the test rate corrected. After a year, they again find three failures out of the 63 units tested. 3/63= 4.76% failures.

In response to the >4% failure rate, the entity decreases the testing interval to 14 years. This means that they will now test 72 units per year (1000/14). The entity has just one year left to get the test rate corrected. After a year, they again find three failures out of the 72 units tested. 3/72= 4.2% failures.

(Note that the entity has tried 10 years, and they were under the 4% limit; and they tried 14 years, and they were over the 4% limit. They must be back at 4% failures or less in the next year, so they might simply elect to go back to 10 years.)

Instead, in response to the 4.2% failure rate, the entity decreases the testing interval to 12 years. This means that they will now test 84 units per year (1000/12). After a year, they again find three failures out of the 84 units tested. 3/84= 3.6% failures.

Entity found that they could maintain the failure rate at no more than 4% failures by maintaining the testing interval at 12 years or less. Entity chose 12-year interval, and effectively extended their TBM (10 years) program by 20%.

A note of practicality is that an entity will probably be in better shape to lengthen the intervals between tests if the failure rate is less than 2%. But the requirements allow for annual adjustments if the entity desires. As a matter of maintenance management, an ever-changing test rate (units tested / year) may be un-workable.

Note that the "5% of components" requirement effectively sets a practical limit of 20-year maximum PBM interval. Also of note is the "3 years" requirement; an entity might arbitrarily extend time intervals from six years to 20 years. In the event that an entity finds a failure rate greater than 4%, then the test rate must be accelerated such that within three years the failure rate must be brought back down to 4% or less.

Here is a table that demonstrates the values discussed:

Year #	Total Population (P)	Test Interval (I)	Units to be Tested (U= P/I)	# of Failures Found (F)	Failure Rate (=F/U)	Decision to Change Interval Yes or No	Interval Chosen
1	1000	10 yrs	100	3	3%	Yes	20 yrs
2	1000	20 yrs	50	3	6%	Yes	16yrs
3	1000	16 yrs	63	3	4.8%	Yes	14 yrs
4	1000	14 yrs	72	3	4.2%	Yes	12 yrs
5	1000	12 yrs	84	3	3.6%	No	12 yrs

Please provide an example of the calculations involved in extending maintenance time intervals using PBM for voltage and current sensing devices.

Note that the following example captures "voltage and current inputs to the protective relays" as all of the various current transformer and potential transformer signals associated with a particular set of relays used for protection of a specific Element. This entity calls this set of protective relays a "Relay Scheme." Thus, this entity chooses to count PT and CT signals as a group instead of individually tracking maintenance activities to specific bushing CT's or specific PT's. An entity is not restricted to this method of counting voltage and current devices, signals and paths. Perhaps another method an entity would prefer would be to simply track every individual PT and CT. Note that a generation maintenance group may well select the latter because they may elect to perform routine off-line tests during generator outages, whereas a transmission maintenance group might create a process that utilizes Real-time system values measured at the relays.

The designation of what constitutes a control circuit component is very dependent upon how an entity performs and tracks the testing of the control circuitry. Some entities test their control circuits on a breaker basis whereas others test their circuitry on a local zone of protection basis. Thus, entities are allowed the latitude to designate their own definitions of control circuit components. Another example of where the entity has some discretion on determining what constitutes a single component is the voltage and current sensing devices, where the entity may choose either to designate a full three-phase set of such devices or a single device as a single component.

And in Attachment A (PBM) the definition of Segment:

Segment –*Components of a consistent design standard, or a particular model or type from a single manufacturer that typically share other common elements. Consistent performance is expected across the entire population of a segment. A segment must contain at least sixty (60) individual components.*

Example:

Entity has 2000 "Relay Schemes," all of which have three current signals supplied from bushing CTs, and three voltage signals supplied from substation bus PT's. All cabling and circuitry was designed and built with a consistent (internal entity) standard, and this population is greater than the minimum sample requirement of 60.

For the sake of further example the following facts are given:

Half of all relay schemes (1,000) are supplied with current signals from ANSI STD C800 bushing CTs and voltage signals from PTs built by ACME Electric MFR CO. All of the relay panels and cable pulls were built with consistent standards, and consistent performance standard expectations exist for the consistent wiring, cabling and instrument transformers within the segment (which is greater than 60).

The other half of the entity's relay schemes have MPC relays with additional monitoring built-in that compare DNP values of voltages and currents (or Watts and VARs), as interpreted by the MPC relays and alarm for an entity-accepted tolerance level of accuracy. This newer segment of their "Voltage and Current Sensing" population is different than the original segment, consistent (standards, construction and performance expectations) within the new segment and constitutes the remainder of the entity's population.

The entity is tracking many thousands of voltage and current signals within 2,000 relay schemes (each consisting of multiple voltage and current signals) in each of these two segments. But half of all of the relay schemes voltage and current signals are monitored; therefore, the voltage and current signals are continuously tested and the circuit will alarm when there is a failure; these alarms have to be verified every 12 years for correct operation.

The entity now has 1,000 relay schemes worth of voltage and current signals remaining that they have elected to count within their relay schemes designation. The entity has instituted a process that requires the verification of these voltage and current signals within each relay scheme (one unit).

(Please note - a problem discovered with a current or voltage signal found at the relay could be caused by anything from the relay, all the way to the signal source itself. Having many sources of problems can easily increase failure rates beyond the rate of failures of just one item (for example just PTs). It is the intent of the SDT to minimize failure rates of all of the equipment to an acceptable level; thus, any failure of any item that gets the signal from source to relay is counted. It is for this reason that the SDT chose to set the boundary at the ability of the signal to be delivered all the way to the relay.

The entity will start out measuring all of the relay scheme voltage and currents at the individual relays within the prescribed Table requirements (12 year max) by measuring the voltage and current values every 10 years. The entity's plan is to test 100 units per year; this is greater than the minimum sample size requirement of 30. For the sake of example only, the following will show three failures per year; reality may well have different numbers of failures every year. PBM requires annual assessment of failures found per units tested. After the first year of tests, the entity finds three failures in the 100 units tested. 3/100= 3% failure rate.

This entity is now allowed to extend the maintenance interval, if they choose. The entity chooses to extend the maintenance interval of this population segment out to 20 years. This represents a rate of 50 units tested per year; entity selects 50 units to be tested in the following year. After that year of testing these 50 units, the entity again finds three failed units. 3/50= 6% failures.

This entity has now exceeded the acceptable failure rate for these devices and must accelerate testing of all of the units at a higher rate, such that the failure rate is found to be less than 4% per year; the entity has three years to get this failure rate down to 4% or less (per year).

In response to the 6% failure rate, the entity decreases the testing interval to 16 years. This means that they will now test 63 units per year (1000/16). The entity has just two years left to get the test rate corrected. After a year, they again find three failures out of the 63 units tested. 3/63= 4.76% failures.

In response to the >4%failure rate, the entity decreases the testing interval to 14 years. This means that they will now test 72 units per year (1000/14). The entity has just one year left to get the test rate corrected. After a year, they again find three failures out of the 72 units tested. 3/72= 4.2% failures.

(Note that the entity has tried 10 years, and they were under the 4% limit; and they tried 14 years, and they were over the 4% limit. They must be back at 4% failures or less in the next year, so they might simply elect to go back to 10 years.)

Instead, in response to the 4.2% failure rate, the entity decreases the testing interval to 12 years. This means that they will now test 84 units per year (1,000/12). After a year, they again find three failures out of the 84 units tested. 3/84= 3.6% failures.

Entity found that they could maintain the failure rate at no more than 4% failures by maintaining the testing interval at 12 years or less. Entity chose 12-year interval and effectively extended their TBM (10 years) program by 20%.

A note of practicality is that an entity will probably be in better shape to lengthen the intervals between tests if the failure rate is less than 2%. But the requirements allow for annual adjustments, if the entity desires. As a matter of maintenance management, an ever-changing test rate (units tested/year) may be un-workable.

Note that the "5% of components" requirement effectively sets a practical limit of 20-year maximum PBM interval. Also of note is the "3 years" requirement; an entity might arbitrarily extend time intervals from six years to 20 years. In the event that an entity finds a failure rate greater than 4%, then the test rate must be accelerated such that within three years the failure rate must be brought back down to 4% or less.

Here is a table that demonstrates the values discussed:

Year #	Total Population (P)	Test Interval (I)	Units to be Tested (U= P/I)	# of Failures Found (F)	Failure Rate (=F/U)	Decision to Change Interval Yes or No	Interval Chose
1	1000	10 yrs	100	3	3%	Yes	20 yrs
2	1000	20 yrs	50	3	6%	Yes	16yrs
3	1000	16 yrs	63	3	4.8%	Yes	14 yrs
4	1000	14 yrs	72	3	4.2%	Yes	12 yrs
5	1000	12 yrs	84	3	3.6%	No	12 yrs

10. Overlapping the Verification of Sections of the Protection System

Tables 1-1 through 1-5 require that every Protection System component be periodically verified. One approach, but not the only method, is to test the entire protection scheme as a unit, from the secondary windings of voltage and current sources to breaker tripping. For practical ongoing verification, sections of the Protection System may be tested or monitored individually. The boundaries of the verified sections must overlap to ensure that there are no gaps in the verification. See Appendix A of this Supplementary Reference for additional discussion on this topic.

All of the methodologies expressed within this report may be combined by an entity, as appropriate, to establish and operate a maintenance program. For example, a Protection System may be divided into multiple overlapping sections with a different maintenance methodology for each section:

- Time-based maintenance with appropriate maximum verification intervals for categories of equipment, as given in the Tables 1-1 through 1-5;
- Monitoring as described in Tables 1-1 through 1-5;
- A Performance-Based Maintenance program as described in Section 9 above, or Attachment A of the standard;
- Opportunistic verification using analysis of Fault records, as described in Section 11

10.1 Frequently Asked Questions:

My system has alarms that are gathered once daily through an auto-polling system; this is not really a conventional SCADA system but does it meet the Table 1 requirements for inclusion as a monitored system?

Yes, provided the auto-polling that gathers the alarms reports those alarms to a location where the action can be initiated to correct the Unresolved Maintenance Issue. This location does not have to be the location of the engineer or the technician that will eventually repair the problem, but rather a location where the action can be initiated.

11. Monitoring by Analysis of Fault Records

Many users of microprocessor relays retrieve Fault event records and oscillographic records by data communications after a Fault. They analyze the data closely if there has been an apparent Misoperation, as NERC standards require. Some advanced users have commissioned automatic Fault record processing systems that gather and archive the data. They search for evidence of component failures or setting problems hidden behind an operation whose overall outcome seems to be correct. The relay data may be augmented with independently captured Digital Fault Recorder (DFR) data retrieved for the same event.

Fault data analysis comprises a legitimate CBM program that is capable of reducing the need for a manual time-interval based check on Protection Systems whose operations are analyzed. Even electromechanical Protection Systems instrumented with DFR channels may achieve some CBM benefit. The completeness of the verification then depends on the number and variety of Faults in the vicinity of the relay that produce relay response records and the specific data captured.

A typical Fault record will verify particular parts of certain Protection Systems in the vicinity of the Fault. For a given Protection System installation, it may or may not be possible to gather within a reasonable amount of time an ensemble of internal and external Fault records that completely verify the Protection System.

For example, Fault records may verify that the particular relays that tripped are able to trip via the control circuit path that was specifically used to clear that Fault. A relay or DFR record may indicate correct operation of the protection communications channel. Furthermore, other nearby Protection Systems may verify that they restrain from tripping for a Fault just outside their respective zones of protection. The ensemble of internal Fault and nearby external Fault event data can verify major portions of the Protection System, and reset the time clock for the Table 1 testing intervals for the verified components only.

What can be shown from the records of one operation is very specific and limited. In a panel with multiple relays, only the specific relay(s) whose operation can be observed without ambiguity should be used. Be careful about using Fault response data to verify that settings or calibration are correct. Unless records have been captured for multiple Faults close to either side of a setting boundary, setting or calibration could still be incorrect.

PMU data, much like DME data, can be utilized to prove various components of the Protection System. Obviously, care must be taken to attribute proof only to the parts of a Protection System that can actually be proven using the PMU or DME data.

If Fault record data is used to show that portions or all of a Protection System have been verified to meet Table 1 requirements, the owner must retain the Fault records used, and the maintenance-related conclusions drawn from this data and used to defer Table 1 tests, for at least the retention time interval given in Section 8.2.

11.1 Frequently Asked Questions:

I use my protective relays for Fault and Disturbance recording, collecting oscillographic records and event records via communications for Fault analysis to meet NERC and DME requirements. What are the maintenance requirements for the relays?

For relays used only as Disturbance Monitoring Equipment, NERC Standard PRC-018-1 R3 & R6 states the maintenance requirements and is being addressed by a standards activity that is revising PRC-002-1 and PRC-018-1. For protective relays "that are designed to provide protection for the BES," this standard applies, even if they also perform DME functions.

12. Importance of Relay Settings in Maintenance Programs

In manual testing programs, many utilities depend on pickup value or zone boundary tests to show that the relays have correct settings and calibration. Microprocessor relays, by contrast, provide the means for continuously monitoring measurement accuracy. Furthermore, the relay digitizes inputs from one set of signals to perform all measurement functions in a single self-monitoring microprocessor system. These relays do not require testing or calibration of each setting.

However, incorrect settings may be a bigger risk with microprocessor relays than with older relays. Some microprocessor relays have hundreds or thousands of settings, many of which are critical to Protection System performance.

Monitoring does not check measuring element settings. Analysis of Fault records may or may not reveal setting problems. To minimize risk of setting errors after commissioning, the user should enforce strict settings data base management, with reconfirmation (manual or automatic) that the installed settings are correct whenever maintenance activity might have changed them; for background and guidance, see [5] in References.

Table 1 requires that settings must be verified to be as specified. The reason for this requirement is simple: With legacy relays (non-microprocessor protective relays), it is necessary to know the value of the intended setting in order to test, adjust and calibrate the relay. Proving that the relay works per specified setting was the de facto procedure. However, with the advanced microprocessor relays, it is possible to change relay settings for the purpose of verifying specific functions and then neglect to return the settings to the specified values. While there is no specific requirement to maintain a settings management process, there remains a need to verify that the settings left in the relay are the intended, specified settings. This need may manifest itself after any of the following:

- One or more settings are changed for any reason.
- A relay fails and is repaired or replaced with another unit.
- A relay is upgraded with a new firmware version.

12.1 Frequently Asked Questions:

How do I approach testing when I have to upgrade firmware of a microprocessor relay?

The entity should ensure that the relay continues to function properly after implementation of firmware changes. Some entities may have a R&D department that might routinely run acceptance tests on devices with firmware upgrades before allowing the upgrade to be installed. Other entities may rely upon the vigorous testing of the firmware OEM. An entity has the latitude to install devices and/or programming that they believe will perform to their satisfaction. If an entity should choose to perform the maintenance activities specified in the Tables following a firmware upgrade, then they may, if they choose, reset the time clock on that set of maintenance activities so that they would not have to repeat the maintenance on its regularly scheduled cycle.

(However, for simplicity in maintenance schedules, some entities may choose to not reset this time clock; it is merely a suggested option.)

If I upgrade my old relays, then do I have to maintain my previous equipment maintenance documentation?

If an equipment item is repaired or replaced, then the entity can restart the maintenance-activity-time-interval-clock, if desired; however, the replacement of equipment does not remove any documentation requirements. The requirements in the standard are intended to ensure that an entity has a maintenance plan, and that the entity adheres to minimum activities and maximum time intervals. The documentation requirements are intended to help an entity demonstrate compliance. For example, saving the dates and records of the last two maintenance activities is intended to demonstrate compliance with the interval. Therefore, if you upgrade or replace equipment, then you still must maintain the documentation for the previous equipment, thus demonstrating compliance with the time interval requirement prior to the replacement action.

We have a number of installations where we have changed our Protection System components. Some of the changes were upgrades, but others were simply system rating changes that merely required taking relays "out-of-service". What are our responsibilities when it comes to "out-of-service" devices?

Assuming that your system up-rates, upgrades and overall changes meet any and all other requirements and standards, then the requirements of PRC-005-4 are simple – if the Protection System component performs a Protection System function, then it must be maintained. If the component no longer performs Protection System functions, then it does not require maintenance activities under the Tables of PRC-005-4. While many entities might physically remove a component that is no longer needed, there is no requirement in PRC-005-4 to remove such component(s). Obviously, prudence would dictate that an "out-of-service" device is truly made inactive. There are no record requirements listed in PRC-005-4 for Protection System components not used.

While performing relay testing of a protective device on our Bulk Electric System, it was discovered that the protective device being tested was either broken or out of calibration. Does this satisfy the relay testing requirement, even though the protective device tested bad, and may be unable to be placed back into service?

Yes, PRC-005-4 requires entities to perform relay testing on protective devices on a given maintenance cycle interval. By performing this testing, the entity has satisfied PRC-005-4 requirement, although the protective device may be unable to be returned to service under normal calibration adjustments. R5 states:

"R5. Each Transmission Owner, Generator Owner, and Distribution Provider shall demonstrate efforts to correct any identified Unresolved Maintenance Issues."

Also, when a failure occurs in a Protection System, power system security may be comprised, and notification of the failure must be conducted in accordance with relevant NERC standards.

If I show the protective device out of service while it is being repaired, then can I add it back as a new protective device when it returns? If not, my relay testing history would show that I was out of compliance for the last maintenance cycle.

The maintenance and testing requirements (R5) state "…shall demonstrate efforts to correct any identified Unresolved Maintenance Issues..." The type of corrective activity is not stated; however, it could include repairs or replacements.

Your documentation requirements will increase, of course, to demonstrate that your device tested bad and had corrective actions initiated. Your regional entity might ask about the status of your corrective actions.

13. Self-Monitoring Capabilities and Limitations

Microprocessor relay proponents have cited the self-monitoring capabilities of these products for nearly 20 years. Theoretically, any element that is monitored does not need a periodic manual test. A problem today is that the community of manufacturers and users has not created clear documentation of exactly what is and is not monitored. Some unmonitored but critical elements are buried in installed systems that are described as self-monitoring.

To utilize the extended time intervals allowed by monitoring, the user must document that the monitoring attributes of the device match the minimum requirements listed in the Table 1.

Until users are able to document how all parts of a system which are required for the protective functions are monitored or verified (with help from manufacturers), they must continue with the unmonitored intervals established in Table 1 and Table 3.

Going forward, manufacturers and users can develop mappings of the monitoring within relays, and monitoring coverage by the relay of user circuits connected to the relay terminals.

To enable the use of the most extensive monitoring (and never again have a hands-on maintenance requirement), the manufacturers of the microprocessor-based self-monitoring components in the Protection System should publish for the user a document or map that shows:

- How all internal elements of the product are monitored for any failure that could impact Protection System performance.
- Which connected circuits are monitored by checks implemented within the product; how to connect and set the product to assure monitoring of these connected circuits; and what circuits or potential problems are not monitored.

This manufacturer's information can be used by the registered entity to document compliance of the monitoring attributes requirements by:

- Presenting or referencing the product manufacturer's documents.
- Explaining in a system design document the mapping of how every component and circuit that is critical to protection is monitored by the microprocessor product(s) or by other design features.
- Extending the monitoring to include the alarm transmission Facilities through which failures are reported within a given time frame to allocate where action can be taken to initiate resolution of the alarm attributed to an Unresolved Maintenance Issue, so that failures of monitoring or alarming systems also lead to alarms and action.
- Documenting the plans for verification of any unmonitored components according to the requirements of Table 1 and Table 3.

13.1 Frequently Asked Questions:

I can't figure out how to demonstrate compliance with the requirements for the highest level of monitoring of Protection Systems. Why does this Maintenance Standard describe a maintenance program approach I cannot achieve?

Demonstrating compliance with the requirements for the highest level of monitoring any particular component of Protection Systems is likely to be very involved, and may include detailed manufacturer documentation of complete internal monitoring within a device, comprehensive design drawing reviews, and other detailed documentation. This standard does not presume to specify what documentation must be developed; only that it must be documented.

There may actually be some equipment available that is capable of meeting these highest levels of monitoring criteria, in which case it may be maintained according to the highest level of monitoring shown on the Tables. However, even if there is no equipment available today that can meet this level of monitoring, the standard establishes the necessary requirements for when such equipment becomes available.

By creating a roadmap for development, this provision makes the standard technology-neutral. The Standard Drafting Team wants to avoid the need to revise the standard in a few years to accommodate technology advances that may be coming to the industry.

14. Notification of Protection System or Automatic Reclosing Failures

When a failure occurs in a Protection System or Automatic Reclosing, power system security may be compromised, and notification of the failure must be conducted in accordance with relevant NERC standard(s). Knowledge of the failure may impact the system operator's decisions on acceptable Loading conditions.

This formal reporting of the failure and repair status to the system operator by the Protection System or Automatic Reclosing owner also encourages the system owner to execute repairs as rapidly as possible. In some cases, a microprocessor relay or carrier set can be replaced in hours; wiring termination failures may be repaired in a similar time frame. On the other hand, a component in an electromechanical or early-generation electronic relay may be difficult to find and may hold up repair for weeks. In some situations, the owner may have to resort to a temporary protection panel, or complete panel replacement.

15. Maintenance Activities

Some specific maintenance activities are a requirement to ensure reliability. An example would be that a BES entity could be prudent in its protective relay maintenance, but if its battery maintenance program is lacking, then reliability could still suffer. The NERC glossary outlines a Protection System as containing specific components. PRC-005-4 requires specific maintenance activities be accomplished within a specific time interval. As noted previously, higher technology equipment can contain integral monitoring capability that actually performs maintenance verification activities routinely and often; therefore, *manual intervention* to perform certain activities on these type components may not be needed.

15.1 Protective Relays (Table 1-1)

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 Element of the BES. Devices that sense thermal, vibration, seismic, gas, or any other non-electrical inputs are excluded.

Non-microprocessor based equipment is treated differently than microprocessor-based equipment in the following ways; the relays should meet the asset owners' tolerances:

- Non-microprocessor devices must be tested with voltage and/or current applied to the device.
- Microprocessor devices may be tested through the integral testing of the device.
  - There is no specific protective relay commissioning test or relay routine test mandated.
  - There is no specific documentation mandated.

15.1.1 Frequently Asked Questions:

What calibration tolerance should be applied on electromechanical relays?

Each entity establishes their own acceptable tolerances when applying protective relaying on their system. For some Protection System components, adjustment is required to bring measurement accuracy within the parameters established by the asset owner based on the specific application of the component. A calibration failure is the result if testing finds the specified parameters to be out of tolerance.

15.2 Voltage & Current Sensing Devices (Table 1-3)

These are the current and voltage sensing devices, usually known as instrument transformers. There is presently a technology available (fiber-optic Hall-effect) that does not utilize conventional transformer technology; these devices and other technologies that produce quantities that represent the primary values of voltage and current are considered to be a type of voltage and current sensing devices included in this standard.

The intent of the maintenance activity is to verify the input to the protective relay from the device that produces the current or voltage signal sample.

There is no specific test mandated for these components. The important thing about these signals is to know that the expected output from these components actually reaches the protective relay. Therefore, the proof of the proper operation of these components also demonstrates the integrity of the wiring (or other medium used to convey the signal) from the current and voltage sensing device, all the way to the protective relay. The following observations apply:

- There is no specific ratio test, routine test or commissioning test mandated.
- There is no specific documentation mandated.
- It is required that the signal be present at the relay.
- This expectation can be arrived at from any of a number of means; including, but not limited to, the following: By calculation, by comparison to other circuits, by commissioning tests, by thorough inspection, or by any means needed to verify the circuit meets the asset owner's Protection System maintenance program.
- An example of testing might be a saturation test of a CT with the test values applied at the relay panel; this, therefore, tests the CT, as well as the wiring from the relay all the back to the CT.
- Another possible test is to measure the signal from the voltage and/or current sensing devices, during Load conditions, at the input to the relay.
- Another example of testing the various voltage and/or current sensing devices is to query the microprocessor relay for the Real-time Loading; this can then be compared to other devices to verify the quantities applied to this relay. Since the input devices have supplied the proper values to the protective relay, then the verification activity has been satisfied. Thus, event reports (and oscillographs) can be used to verify that the voltage and current sensing devices are performing satisfactorily.
- Still another method is to measure total watts and VArs around the entire bus; this should add up to zero watts and zero VArs, thus proving the voltage and/or current sensing devices system throughout the bus.
- Another method for proving the voltage and/or current-sensing devices is to complete commissioning tests on all of the transformers, cabling, fuses and wiring.
- Any other method that verifies the input to the protective relay from the device that produces the current or voltage signal sample.

15.2.1 Frequently Asked Questions:

What is meant by "… verify the current and voltage circuit inputs from the voltage and current sensing devices to the protective relays … " Do we need to perform ratio, polarity and saturation tests every few years?

No. You must verify that the protective relay is receiving the expected values from the voltage and current-sensing devices (typically voltage and current transformers). This can be as difficult as is proposed by the question (with additional testing on the cabling and substation wiring to ensure that the values arrive at the relays); or simplicity can be achieved by other verification methods. While some examples follow, these are not intended to represent an all-inclusive list; technology advances and ingenuity should not be excluded from making comparisons and verifications:

- Compare the secondary values, at the relay, to a metering circuit, fed by different current transformers, monitoring the same line as the questioned relay circuit.
- Compare the individual phase secondary values at the relay panel (with additional testing on the panel wiring to ensure that the values arrive at those relays) with the other phases, and verify that residual currents are within expected bounds.
- Observe all three phase currents and the residual current at the relay panel with an oscilloscope, observing comparable magnitudes and proper phase relationship, with additional testing on the panel wiring to ensure that the values arrive at the relays.
- Compare the values, as determined by the questioned relay (such as, but not limited to, a query to the microprocessor relay) to another protective relay monitoring the same line, with currents supplied by different CTs.
- Compare the secondary values, at the relay with values measured by test instruments (such as, but not limited to multi-meters, voltmeter, clamp-on ammeters, etc.) and verified by calculations and known ratios to be the values expected. For example, a single PT on a 100KV bus will have a specific secondary value that, when multiplied by the PT ratio, arrives at the expected bus value of 100KV.
- Query SCADA for the power flows at the far end of the line protected by the questioned relay, compare those SCADA values to the values as determined by the questioned relay.
- Totalize the Watts and VARs on the bus and compare the totals to the values as seen by the questioned relay.

The point of the verification procedure is to ensure that all of the individual components are functioning properly; and that an ongoing proactive procedure is in place to re-check the various components of the protective relay measuring Systems.

Is wiring insulation or hi-pot testing required by this Maintenance Standard?

No, wiring insulation and equipment hi-pot testing are not specifically required by the Maintenance Standard. However, if the method of verifying CT and PT inputs to the relay involves some other method than actual observation of current and voltage transformer secondary inputs to the relay, it might be necessary to perform some sort of cable integrity test to verify that the instrument transformer secondary signals are actually making it to the relay and not being shunted off to ground. For instance, you could use CT excitation tests and PT turns ratio tests

and compare to baseline values to verify that the instrument transformer outputs are acceptable. However, to conclude that these acceptable transformer instrument output signals are actually making it to the relay inputs, it also would be necessary to verify the insulation of the wiring between the instrument transformer and the relay.

My plant generator and transformer relays are electromechanical and do not have metering functions, as do microprocessor- based relays. In order for me to compare the instrument transformer inputs to these relays to the secondary values of other metered instrument transformers monitoring the same primary voltage and current signals, it would be necessary to temporarily connect test equipment, like voltmeters and clamp on ammeters, to measure the input signals to the relays. This practice seems very risky, and a plant trip could result if the technician were to make an error while measuring these current and voltage signals. How can I avoid this risk? Also, what if no other instrument transformers are available which monitor the same primary voltage or current signal?

Comparing the input signals to the relays to the outputs of other independent instrument transformers monitoring the same primary current or voltage is just one method of verifying the instrument transformer inputs to the relays, but is not required by the standard. Plants can choose how to best manage their risk. If online testing is deemed too risky, offline tests, such as, but not limited to, CT excitation test and PT turns ratio tests can be compared to baseline data and be used in conjunction with CT and PT secondary wiring insulation verification tests to adequately “verify the current and voltage circuit inputs from the voltage and current sensing devices to the protective relays …” while eliminating the risk of tripping an in service generator or transformer. Similarly, this same offline test methodology can be used to verify the relay input voltage and current signals to relays when there are no other instrument transformers monitoring available for purposes of signal comparison.

15.3 Control circuitry associated with protective functions (Table 1-5)

This component of Protection Systems includes the trip coil(s) of the circuit breaker, circuit switcher or any other interrupting device. It includes the wiring from the batteries to the relays. It includes the wiring (or other signal conveyance) from every trip output to every trip coil. It includes any device needed for the correct processing of the needed trip signal to the trip coil of the interrupting device; this requirement is meant to capture inputs and outputs to and from a protective relay that are necessary for the correct operation of the protective functions. In short, every trip path must be verified; the method of verification is optional to the asset owner. An example of testing methods to accomplish this might be to verify, with a volt-meter, the existence of the proper voltage at the open contacts, the open circuited input circuit and at the trip coil(s). As every parallel trip path has similar failure modes, each trip path from relay to trip coil must be verified. Each trip coil must be tested to trip the circuit breaker (or other interrupting device) at least once. There is a requirement to operate the circuit breaker (or other interrupting device) at least once every six years as part of the complete functional test. If a suitable monitoring system is installed that verifies every parallel trip path, then the manual-intervention testing of those parallel trip paths can be eliminated; however, the actual operation of the circuit breaker must still occur at least once every six years. This six-year tripping requirement can be completed as easily as tracking the Real-time Fault-clearing operations on the circuit breaker, or tracking the trip coil(s) operation(s) during circuit breaker routine maintenance actions.

The circuit-interrupting device should not be confused with a motor-operated disconnect. The intent of this standard is to require maintenance intervals and activities on Protection Systems equipment, and not just all system isolating equipment.

It is necessary, however, to classify a device that actuates a high-speed auto-closing ground switch as an interrupting device, if this ground switch is utilized in a Protection System and forces a ground Fault to occur that then results in an expected Protection System operation to clear the forced ground Fault. The SDT believes that this is essentially a transferred-tripping device without the use of communications equipment. If this high-speed ground switch is "…designed to provide protection for the BES…" then this device needs to be treated as any other Protection System component. The control circuitry would have to be tested within 12 years, and any electromechanically operated device will have to be tested every six years. If the spring-operated ground switch can be disconnected from the solenoid triggering unit, then the solenoid triggering unit can easily be tested without the actual closing of the ground blade.

The dc control circuitry also includes each auxiliary tripping relay (94) and each lock-out relay (86) that may exist in any particular trip scheme. If the lock-out relays (86) are electromechanical type components, then they must be trip tested. The PSMT SDT considers these components to share some similarities in failure modes as electromechanical protective relays; as such, there is a six-year maximum interval between mandated maintenance tasks unless PBM is applied.

Contacts of the 86 and/or 94 that pass the trip current on to the circuit interrupting device trip coils will have to be checked as part of the 12 year requirement. Contacts of the 86 and/or 94 lock relay that operate non-BES interrupting devices are not required. Normally-open contacts that are not used to pass a trip signal and normally-closed contacts do not have to be verified. Verification of the tripping paths is the requirement.

New technology is also accommodated here; there are some tripping systems that have replaced the traditional hard-wired trip circuitry with other methods of trip-signal conveyance such as fiber-optics. It is the intent of the PSMT SDT to include this, and any other, technology that is used to convey a trip signal from a protective relay to a circuit breaker (or other interrupting device) within this category of equipment. The requirement for these systems is verification of the tripping path.

Monitoring of the control circuit integrity allows for no maintenance activity on the control circuit (excluding the requirement to operate trip coils and electromechanical lockout and/or tripping auxiliary relays). Monitoring of integrity means to monitor for continuity and/or presence of voltage on each trip path. For Ethernet or fiber-optic control systems, monitoring of integrity means to monitor communication ability between the relay and the circuit breaker.

15.3.1 Frequently Asked Questions:

Is it permissible to verify circuit breaker tripping at a different time (and interval) than when we verify the protective relays and the instrument transformers?

Yes, provided the entire Protective System is tested within the individual component's maximum allowable testing intervals.

The Protection System Maintenance Standard describes requirements for verifying the tripping of circuit breakers. What is this telling me about maintenance of circuit breakers?

Requirements in PRC-005-4 are intended to verify the integrity of tripping circuits, including the breaker trip coil, as well as the presence of auxiliary supply (usually a battery) for energizing the trip coil if a protection function operates. Beyond this, PRC-005-4 sets no requirements for verifying circuit breaker performance, or for maintenance of the circuit breaker.

How do I test each dc Control Circuit trip path, as established in Table 1-5 "Protection System Control Circuitry (Trip coils and auxiliary relays)"?

Table 1-5 specifies that each breaker trip coil and lockout relays that carry trip current to a trip coil must be operated within the specified time period. The required operations may be via targeted maintenance activities, or by documented operation of these devices for other purposes such as Fault clearing.

Are high-speed ground switch trip coils included in the dc control circuitry?

Yes. PRC-005-4 includes high-speed grounding switch trip coils within the dc control circuitry to the degree that the initiating Protection Systems are characterized as "transmission Protection Systems."

Does the control circuitry and trip coil of a non-BES breaker, tripped via a BES protection component, have to be tested per Table 1.5? (Refer to Table 3 for examples 1 and 2) Example 1: A non-BES circuit breaker that is tripped via a Protection System to which PRC-005-4 applies might be (but is not limited to) a 12.5KV circuit breaker feeding (non-black-start) radial Loads but has a trip that originates from an under-frequency (81) relay.

- The relay must be verified.
- The voltage signal to the relay must be verified.
- All of the relevant dc supply tests still apply.
- The unmonitored trip circuit between the relay and any lock-out or auxiliary relay must be verified every 12 years.
- The unmonitored trip circuit between the lock-out (or auxiliary relay) and the non-BES breaker does not have to be proven with an electrical trip.
- In the case where there is no lock-out or auxiliary tripping relay used, the trip circuit to the non-BES breaker does not have to be proven with an electrical trip.
- The trip coil of the non-BES circuit breaker does not have to be individually proven with an electrical trip.

Example 2: A Transmission Owner may have a non-BES breaker that is tripped via a Protection System to which PRC-005-4 applies, which may be (but is not limited to) a 13.8 KV circuit breaker feeding (non-black-start) radial Loads but has a trip that originates from a BES 115KV line relay.

- The relay must be verified
- The voltage signal to the relay must be verified
- All of the relevant dc supply tests still apply
- The unmonitored trip circuit between the relay and any lock-out (86) or auxiliary (94) relay must be verified every 12 years

- The unmonitored trip circuit between the lock-out (86) (or auxiliary (94)) relay and the non-BES breaker does not have to be proven with an electrical trip
- In the case where there is no lockout (86) or auxiliary (94) tripping relay used, the trip circuit to the non-BES breaker does not have to be proven with an electrical trip.
- The trip coil of the non-BES circuit breaker does not have to be individually proven with an electrical trip

Example 3: A Generator Owner may have a non-BES circuit breaker that is tripped via a Protection System to which PRC-005-4 applies, such as the generator field breaker and low-side breakers on station service/excitation transformers connected to the generator bus.

Trip testing of the generator field breaker and low side station service/excitation transformer breaker(s) via lockout or auxiliary tripping relays are not required since these breakers may be associated with radially fed loads and are not considered to be BES breakers. An example of an otherwise non-BES circuit breaker that is tripped via a BES protection component might be (but is not limited to) a 6.9kV station service transformer source circuit breaker but has a trip that originates from a generator differential (87) relay.

- The differential relay must be verified.
- The current signals to the relay must be verified.
- All of the relevant dc supply tests still apply.
- The unmonitored trip circuit between the relay and any lock-out or auxiliary relay must be verified every 12 years.
- The unmonitored trip circuit between the lock-out (or auxiliary relay) and the non-BES breaker does not have to be proven with an electrical trip.
- In the case where there is no lock-out or auxiliary tripping relay used, the trip circuit to the non-BES breaker does not have to be proven with an electrical trip.
- The trip coil of the non-BES circuit breaker does not have to be individually proven with an electrical trip.

However, it is very prudent to verify the tripping of such breakers for the integrity of the overall generation plant.

Do I have to verify operation of breaker "a" contacts or any other normally closed auxiliary contacts in the trip path of each breaker as part of my control circuit test?

Operation of normally-closed contacts does not have to be verified. Verification of the tripping paths is the requirement. The continuity of the normally closed contacts will be verified when the tripping path is verified.

15.4 Batteries and DC Supplies (Table 1-4)

The NERC definition of a Protection System is:

- Protective relays which respond to electrical quantities,
- Communications Systems necessary for correct operation of protective functions,
- Voltage and current sensing devices providing inputs to protective relays,

- Station dc supply associated with protective functions (including station batteries, battery chargers, and non-battery-based dc supply), and
- Control circuitry associated with protective functions through the trip coil(s) of the circuit breakers or other interrupting devices.

The station battery is not the only component that provides dc power to a Protection System. In the new definition for Protection System, "station batteries" are replaced with "station dc supply" to make the battery charger and dc producing stored energy devices (that are not a battery) part of the Protection System that must be maintained.

The PSMT SDT recognizes that there are several technological advances in equipment and testing procedures that allow the owner to choose how to verify that a battery string is free of open circuits. The term "continuity" was introduced into the standard to allow the owner to choose how to verify continuity of a battery set by various methods, and not to limit the owner to other conventional methods of showing continuity. Continuity, as used in Table 1-4 of the standard, refers to verifying that there is a continuous current path from the positive terminal of the station battery set to the negative terminal. Without verifying continuity of a station battery, there is no way to determine that the station battery is available to supply dc power to the station. An open battery string will be an unavailable power source in the event of loss of the battery charger.

Batteries cannot be a unique population segment of a Performance-Based Maintenance Program (PBM) because there are too many variables in the electrochemical process to completely isolate all of the performance-changing criteria necessary for using PBM on battery Systems. However, nothing precludes the use of a PBM process for any other part of a dc supply besides the batteries themselves.

15.4.1 Frequently Asked Questions:

What constitutes the station dc supply, as mentioned in the definition of Protective System?

The previous definition of Protection System includes batteries, but leaves out chargers. The latest definition includes chargers, as well as dc systems that do not utilize batteries. This revision of PRC-005-4 is intended to capture these devices that were not included under the previous definition. The station direct current (dc) supply normally consists of two components: the battery charger and the station battery itself. There are also emerging technologies that provide a source of dc supply that does not include either a battery or charger.

<u>Battery Charger</u> - The battery charger is supplied by an available ac source. At a minimum, the battery charger must be sized to charge the battery (after discharge) and supply the constant dc load. In many cases, it may be sized also to provide sufficient dc current to handle the higher energy requirements of tripping breakers and switches when actuated by the protective relays in the Protection System.

<u>Station Battery</u> - Station batteries provide the dc power required for tripping and for supplying normal dc power to the station in the event of loss of the battery charger. There are several technologies of battery that require unique forms of maintenance as established in Table 1-4.

<u>Emerging Technologies</u> - Station dc supplies are currently being developed that use other energy storage technologies besides the station battery to prevent loss of the station dc supply when ac

power is lost. Maintenance of these station dc supplies will require different kinds of tests and inspections. Table 1-4 presents maintenance activities and maximum allowable testing intervals for these new station dc supply technologies. However, because these technologies are relatively new, the maintenance activities for these station dc supplies may change over time.

What did the PSMT SDT mean by "continuity" of the dc supply?

The PSMT SDT recognizes that there are several technological advances in equipment and testing procedures that allow the owner to choose how to verify that a battery string is free of open circuits. The term "continuity" was introduced into the standard to allow the owner to choose how to verify continuity (no open circuits) of a battery set by various methods, and not to limit the owner to other conventional methods of showing continuity – lack of an open circuit. Continuity, as used in Table 1-4 of the standard, refers to verifying that there is a continuous current path from the positive terminal of the station battery set to the negative terminal (no open circuit). Without verifying continuity of a station battery, there is no way to determine that the station battery is available to supply dc power to the station. Whether it is caused from an open cell or a bad external connection, an open battery string will be an unavailable power source in the event of loss of the battery charger.

The current path through a station battery from its positive to its negative connection to the dc control circuits is composed of two types of elements. These path elements are the electrochemical path through each of its cells and all of the internal and external metallic connections and terminations of the batteries in the battery set. If there is loss of continuity (an open circuit) in any part of the electrochemical or metallic path, the battery set will not be available for service. In the event of the loss of the ac source or battery charger, the battery must be capable of supplying dc current, both for continuous dc loads and for tripping breakers and switches. Without continuity, the battery cannot perform this function.

At generating stations and large transmission stations where battery chargers are capable of handling the maximum current required by the Protection System, there are still problems that could potentially occur when the continuity through the connected battery is interrupted.

- Many battery chargers produce harmonics which can cause failure of dc power supplies in microprocessor-based protective relays and other electronic devices connected to station dc supply. In these cases, the substation battery serves as a filter for these harmonics. With the loss of continuity in the battery, the filter provided by the battery is no longer present.
- Loss of electrical continuity of the station battery will cause, in most battery chargers, regardless of the battery charger's output current capability, a delayed response in full output current from the charger. Almost all chargers have an intentional one- to two-second delay to switch from a low substation dc load current to the maximum output of the charger. This delay would cause the opening of circuit breakers to be delayed, which could violate system performance standards.

Monitoring of the station dc supply voltage will not indicate that there is a problem with the dc current path through the battery, unless the battery charger is taken out of service. At that time, a break in the continuity of the station battery current path will be revealed because there will be no voltage on the station dc circuitry. This particular test method, while proving battery continuity, may not be acceptable to all installations.

Although the standard prescribes what must be accomplished during the maintenance activity, it does not prescribe how the maintenance activity should be accomplished. There are several methods that can be used to verify the electrical continuity of the battery. These are not the only possible methods, simply a sampling of some methods:

- One method is to measure that there is current flowing through the battery itself by a simple clamp on milliamp-range ammeter. A battery is always either charging or discharging. Even when a battery is charged, there is still a measurable float charge current that can be detected to verify that there is continuity in the electrical path through the battery.
- A simple test for continuity is to remove the battery charger from service and verify that the battery provides voltage and current to the dc system. However, the behavior of the various dc-supplied equipment in the station should be considered before using this approach.
- Manufacturers of microprocessor-controlled battery chargers have developed methods for their equipment to periodically (or continuously) test for battery continuity. For example, one manufacturer periodically reduces the float voltage on the battery until current from the battery to the dc load can be measured to confirm continuity.
- Applying test current (as in some ohmic testing devices, or devices for locating dc grounds) will provide a current that when measured elsewhere in the string, will prove that the circuit is continuous.
- Internal ohmic measurements of the cells and units of lead-acid batteries (VRLA & VLA) can detect lack of continuity within the cells of a battery string; and when used in conjunction with resistance measurements of the battery's external connections, can prove continuity. Also some methods of taking internal ohmic measurements, by their very nature, can prove the continuity of a battery string without having to use the results of resistance measurements of the external connections.
- Specific gravity tests could infer continuity because without continuity there could be no charging occurring; and if there is no charging, then specific gravity will go down below acceptable levels over time.

No matter how the electrical continuity of a battery set is verified, it is a necessary maintenance activity that must be performed at the intervals prescribed by Table 1-4 to insure that the station dc supply has a path that can provide the required current to the Protection System at all times.

When should I check the station batteries to see if they have sufficient energy to perform as manufactured?

The answer to this question depends on the type of battery (valve-regulated lead-acid, vented lead-acid, or nickel-cadmium) and the maintenance activity chosen.

For example, if you have a valve-regulated lead-acid (VRLA) station battery, and you have chosen to evaluate the measured cell/unit internal ohmic values to the battery cell's baseline, you will have to perform verification at a maximum maintenance interval of no greater than every six months. While this interval might seem to be quite short, keep in mind that the six-

month interval is important for VRLA batteries; this interval provides an accumulation of data that better shows when a VRLA battery is incapable of performing as manufactured.

If, for a VRLA station battery, you choose to conduct a performance capacity test on the entire station battery as the maintenance activity, then you will have to perform verification at a maximum maintenance interval of no greater than every three calendar years.

How is a baseline established for cell/unit internal ohmic measurements?

Establishment of cell/unit internal ohmic baseline measurements should be completed when lead-acid batteries are newly installed. To ensure that the baseline ohmic cell/unit values are most indicative of the station battery's ability to perform as manufactured, they should be made at some point in time after the installation to allow the cell chemistry to stabilize after the initial freshening charge. An accepted industry practice for establishing baseline values is after six-months of installation, with the battery fully charged and in service. However, it is recommended that each owner, when establishing a baseline, should consult the battery manufacturer for specific instructions on establishing an ohmic baseline for their product, if available.

When internal ohmic measurements are taken, the same make/model test equipment should be used to establish the baseline and used for the future trending of the cells internal ohmic measurements because of variances in test equipment and the type of ohmic measurement used by different manufacturer's equipment. Keep in mind that one manufacturer's "Conductance" test equipment does not produce similar results as another manufacturer's "Conductance" test equipment, even though both manufacturers have produced "Ohmic" test equipment. Therefore, for meaningful results to an established baseline, the same make/model of instrument should be used.

For all new installations of valve-regulated lead-acid (VRLA) batteries and vented lead-acid (VLA) batteries, where trending of the cells internal ohmic measurements to a baseline are to be used to determine the ability of the station battery to perform as manufactured, the establishment of the baseline, as described above, should be followed at the time of installation to insure the most accurate trending of the cell/unit. However, often for older VRLA batteries, the owners of the station batteries have not established a baseline at installation. Also for owners of VLA batteries who want to establish a maintenance activity which requires trending of measured ohmic values to a baseline, there was typically no baseline established at installation of the station battery to trend to.

To resolve the problem of the unavailability of baseline internal ohmic measurements for the individual cell/unit of a station battery, many manufacturers of internal ohmic measurement devices have established libraries of baseline values for VRLA and VLA batteries using their testing device. Also, several of the battery manufacturers have libraries of baselines for their products that can be used to trend to. However, it is important that when using battery manufacturer-supplied data that it is verified that the baseline readings to be used were taken with the same ohmic testing device that will be used for future measurements (for example "Conductance Readings" from one manufacturer's test equipment do not correlate to "Impedance Readings" from a different manufacturer's test equipment). Although many manufacturers may have provided baseline values, which will allow trending of the internal ohmic measurements over the remaining life of a station battery, these baselines are not the actual cell/unit measurements for the battery being trended. It is important to have a baseline tailored to the station battery to more accurately use the tool of ohmic measurement trending. That more customized baseline

can only be created by following the establishment of a baseline for each cell/unit at the time of installation of the station battery.

Why determine the State of Charge?

Even though there is no present requirement to check the state of charge of a battery, it can be a very useful tool in determining the overall condition of a battery system. The following discussions are offered as a general reference.

When a battery is fully charged, the battery is available to deliver its existing capacity. As a battery is discharged, its ability to deliver its maximum available capacity is diminished. It is necessary to determine if the state of charge has dropped to an unacceptable level.

What is State of Charge and how can it be determined in a station battery?

The state of charge of a battery refers to the ratio of residual capacity at a given instant to the maximum capacity available from the battery. When a battery is fully charged, the battery is available to deliver its existing capacity. As a battery is discharged, its ability to deliver its maximum available capacity is diminished. Knowing the amount of energy left in a battery compared with the energy it had when it was fully charged gives the user an indication of how much longer a battery will continue to perform before it needs recharging.

For vented lead-acid (VLA) batteries which use accessible liquid electrolyte, a hydrometer can be used to test the specific gravity of each cell as a measure of its state of charge. The hydrometer depends on measuring changes in the weight of the active chemicals. As the battery discharges, the active electrolyte, sulfuric acid, is consumed and the concentration of the sulfuric acid in water is reduced. This, in turn, reduces the specific gravity of the solution in direct proportion to the state of charge. The actual specific gravity of the electrolyte can, therefore, be used as an indication of the state of charge of the battery. Hydrometer readings may not tell the whole story, as it takes a while for the acid to get mixed up in the cells of a VLA battery. If measured right after charging, you might see high specific gravity readings at the top of the cell, even though it is much less at the bottom. Conversely, if taken shortly after adding water to the cell, the specific gravity readings near the top of the cell will be lower than those at the bottom.

Nickel-cadmium batteries, where the specific gravity of the electrolyte does not change during battery charge and discharge, and valve-regulated lead-acid (VRLA) batteries, where the electrolyte is not accessible, cannot have their state of charge determined by specific gravity readings. For these two types of batteries, and for VLA batteries also, where another method besides taking hydrometer readings is desired, the state of charge may be determined by taking voltage and current readings at the battery terminals. The methods employed to obtain accurate readings vary for the different battery types. Manufacturers' information and IEEE guidelines can be consulted for specifics; (see IEEE 1106 Annex B for Nickel Cadmium batteries, IEEE 1188 Annex A for VRLA batteries and IEEE 450 for VLA batteries.

Why determine the Connection Resistance?

High connection resistance can cause abnormal voltage drop or excessive heating during discharge of a station battery. During periods of a high rate of discharge of the station battery, a very high resistance can cause severe damage. The maintenance requirement to verify battery terminal connection resistance in Table 1-4 is established to verify that the integrity of all battery electrical connections is acceptable. This verification includes cell-to-cell (intercell) and external

circuit terminations. Your method of checking for acceptable values of intercell and terminal connection resistance could be by individual readings, or a combination of the two. There are test methods presently that can read post termination resistances and resistance values between external posts. There are also test methods presently available that take a combination reading of the post termination connection resistance plus the intercell resistance value plus the post termination connection resistance value. Either of the two methods, or any other method, that can show if the adequacy of connections at the battery posts is acceptable.

Adequacy of the electrical terminations can be determined by comparing resistance measurements for all connections taken at the time of station battery's installation to the same resistance measurements taken at the maintenance interval chosen, not to exceed the maximum maintenance interval of Table 1-4. Trending of the interval measurements to the baseline measurements will identify any degradation in the battery connections. When the connection resistance values exceed the acceptance criteria for the connection, the connection is typically disassembled, cleaned, reassembled and measurements taken to verify that the measurements are adequate when compared to the baseline readings.

What conditions should be inspected for visible battery cells?

The maintenance requirement to inspect the cell condition of all station battery cells where the cells are visible is a maintenance requirement of Table 1-4. Station batteries are different from any other component in the Protection Station because they are a perishable product due to the electrochemical process which is used to produce dc electrical current and voltage. This inspection is a detailed visual inspection of the cells for abnormalities that occur in the aging process of the cell. In VLA battery visual inspections, some of the things that the inspector is typically looking for on the plates are signs of sulfation of the plates, abnormal colors (which are an indicator of sulfation or possible copper contamination) and abnormal conditions such as cracked grids. The visual inspection could look for symptoms of hydration that would indicate that the battery has been left in a completely discharged state for a prolonged period. Besides looking at the plates for signs of aging, all internal connections, such as the bus bar connection to each plate, and the connections to all posts of the battery need to be visually inspected for abnormalities. In a complete visual inspection for the condition of the cell the cell plates, separators and sediment space of each cell must be looked at for signs of deterioration. An inspection of the station battery's cell condition also includes looking at all terminal posts and cell-to-cell electric connections to ensure they are corrosion free. The case of the battery containing the cell, or cells, must be inspected for cracks and electrolyte leaks through cracks and the post seals.

This maintenance activity cannot be extended beyond the maximum maintenance interval of Table 1-4 by a Performance-Based Maintenance Program (PBM) because of the electrochemical aging process of the station battery, nor can there be any monitoring associated with it because there must be a visual inspection involved in the activity. A remote visual inspection could possibly be done, but its interval must be no greater than the maximum maintenance interval of Table 1-4.

Why is it necessary to verify the battery string can perform as manufactured? I only care that the battery can trip the breaker, which means that the battery can perform as designed. I oversize my batteries so that even if the battery cannot perform as manufactured, it can still trip my breakers.

The fundamental answer to this question revolves around the concept of battery performance "as designed" vs. battery performance "as manufactured." The purpose of the various sections of Table 1-4 of this standard is to establish requirements for the Protection System owner to maintain the batteries, to ensure they will operate the equipment when there is an incident that requires dc power, and ensure the batteries will continue to provide adequate service until at least the next maintenance interval. To meet these goals, the correct battery has to be properly selected to meet the design parameters, and the battery has to deliver the power it was manufactured to provide.

When testing batteries, it may be difficult to determine the original design (i.e., load profile) of the dc system. This standard is not intended as a design document, and requirements relating to design are, therefore, not included.

Where the dc load profile is known, the best way to determine if the system will operate as designed is to conduct a service test on the battery. However, a service test alone might not fully determine if the battery is healthy. A battery with 50% capacity may be able to pass a service test, but the battery would be in a serious state of deterioration and could fail at some point in the near future.

To ensure that the battery will meet the required load profile and continue to meet the load profile until the next maintenance interval, the installed battery must be sized correctly (i.e., a correct design), and it must be in a good state of health. Since the design of the dc system is not within the scope of the standard, the only consistent and reliable method to ensure that the battery is in a good state of health is to confirm that it can perform as manufactured. If the battery can perform as manufactured and it has been designed properly, the system should operate properly until the next maintenance interval.

How do I verify the battery string can perform as manufactured?

Optimally, actual battery performance should be verified against the manufacturer's rating curves. The best practice for evaluating battery performance is via a performance test. However, due to both logistical and system reliability concerns, some Protection System owners prefer other methods to determine if a battery can perform as manufactured. There are several battery parameters that can be evaluated to determine if a battery can perform as manufactured. Ohmic measurements and float current are two examples of parameters that have been reported to assist in determining if a battery string can perform as manufactured.

The evaluation of battery parameters in determining battery health is a complex issue, and is not an exact science. This standard gives the user an opportunity to utilize other measured parameters to determine if the battery can perform as manufactured. It is the responsibility of the Protection System owner, however, to maintain a documented process that demonstrates the chosen parameter(s) and associated methodology used to determine if the battery string can perform as manufactured.

Whatever parameters are used to evaluate the battery (ohmic measurements, float current, float voltages, temperature, specific gravity, performance test, or combination thereof), the goal is to determine the value of the measurement (or the percentage change) at which the battery fails to perform as manufactured, or the point where the battery is deteriorating so rapidly that it will not perform as manufactured before the next maintenance interval.

This necessitates the need for establishing and documenting a baseline. A baseline may be required of every individual cell, a particular battery installation, or a specific make, model, or size of a cell. Given a consistent cell manufacturing process, it may be possible to establish a baseline number for the cell (make/model/type) and, therefore, a subsequent baseline for every installation would not be necessary. However, future installations of the same battery types should be spot-checked to ensure that your baseline remains applicable.

Consistent testing methods by trained personnel are essential. Moreover, it is essential that these technicians utilize the same make/model of ohmic test equipment each time readings are taken in order to establish a meaningful and accurate trend line against the established baseline. The type of probe and its location (post, connector, etc.) for the reading need to be the same for each subsequent test. The room temperature should be recorded with the readings for each test as well. Care should be taken to consider any factors that might lead a trending program to become invalid.

Float current along with other measureable parameters can be used in lieu of or in concert with ohmic measurement testing to measure the ability of a battery to perform as manufactured. The key to using any of these measurement parameters is to establish a baseline and the point where the reading indicates that the battery will not perform as manufactured.

The establishment of a baseline may be different for various types of cells and for different types of installations. In some cases, it may be possible to obtain a baseline number from the battery manufacturer, although it is much more likely that the baseline will have to be established after the installation is complete. To some degree, the battery may still be "forming" after installation; consequently, determining a stable baseline may not be possible until several months after the battery has been in service.

The most important part of this process is to determine the point where the ohmic reading (or other measured parameter(s)) indicates that the battery cannot perform as manufactured. That point could be an absolute number, an absolute change, or a percentage change of an established baseline.

Since there are no universally-accepted repositories of this information, the Protection System owner will have to determine the value/percentage where the battery cannot perform as manufactured (heretofore referred to as a failed cell). This is the most difficult and important part of the entire process.

To determine the point where the battery fails to perform as manufactured, it is helpful to have a history of a battery type, if the data includes the parameter(s) used to evaluate the battery's ability to perform as manufactured against the actual demonstrated performance/capacity of a battery/cell.

For example, when an ohmic reading has been recorded that the user suspects is indicating a failed cell, a performance test of that cell (or string) should be conducted in order to prove/quantify that the cell has failed. Through this process, the user needs to determine the ohmic value at which the performance of the cell has dropped below 80% of the manufactured, rated performance. It is likely that there may be a variation in ohmic readings that indicates a failed cell (possibly significant). It is prudent to use the most conservative values to determine the point at which the cell should be marked for replacement. Periodically, the user should demonstrate that an "adequate" ohmic reading equates to an adequate battery performance (>80% of capacity).

Similarly, acceptance criteria for "good" and "failed" cells should be established for other parameters such as float current, specific gravity, etc., if used to determine the ability of a battery to function as designed.

What happens if I change the make/model of ohmic test equipment after the battery has been installed for a period of time?

If a user decides to switch testers, either voluntarily or because the equipment is not supported/sold any longer, the user may have to establish a new base line and new parameters that indicate when the battery no longer performs as manufactured. The user always has a choice to perform a capacity test in lieu of establishing new parameters.

What are some of the differences between lead-acid and nickel-cadmium batteries?

There is a marked difference in the aging process of lead acid and nickel-cadmium station batteries. The difference in the aging process of these two types of batteries is chiefly due to the electrochemical process of the battery type. Aging and eventual failure of lead acid batteries is due to expansion and corrosion of the positive grid structure, loss of positive plate active material, and loss of capacity caused by physical changes in the active material of the positive plates. In contrast, the primary failure of nickel-cadmium batteries is due to the gradual linear aging of the active materials in the plates. The electrolyte of a nickel-cadmium battery only facilitates the chemical reaction (it functions only to transfer ions between the positive and negative plates), but is not chemically altered during the process like the electrolyte of a lead acid battery. A lead acid battery experiences continued corrosion of the positive plate and grid structure throughout its operational life while a nickel-cadmium battery does not.

Changes to the properties of a lead acid battery when periodically measured and trended to a baseline, can indicate aging of the grid structure, positive plate deterioration, or changes in the active materials in the plate.

Because of the clear differences in the aging process of lead acid and nickel-cadmium batteries, there are no significantly measurable properties of the nickel-cadmium battery that can be measured at a periodic interval and trended to determine aging. For this reason, Table 1-4(c) (Protection System Station dc supply Using nickel-cadmium [NiCad] Batteries) only specifies one minimum maintenance activity and associated maximum maintenance interval necessary to verify that the station battery can perform as manufactured by evaluating cell/unit measurements indicative of battery performance against the station battery baseline. This maintenance activity is to conduct a performance or modified performance capacity test of the entire battery bank.

Why in Table 1-4 of PRC-005-4 is there a maintenance activity to inspect the structural intergrity of the battery rack?

The purpose of this inspection is to verify that the battery rack is correctly installed and has no deterioration that could weaken its structural integrity.

Because the battery rack is specifically manufactured for the battery that is mounted on it, weakening of its structural members by rust or corrosion can physically jeopardize the battery.

What is required to comply with the "Unintentional dc Grounds" requirement?

In most cases, the first ground that appears on a battery is not a problem. It is the unintentional ground that appears on the opposite pole that becomes problematic. Even then many systems

are designed to operate favorably under some unintentional DC ground situations. It is up to the owner of the Protection System to determine if corrective actions are needed on detected unintentional DC grounds. The standard merely requires that a check be made for the existence of Unintentional DC Grounds. Obviously, a “check-off” of some sort will have to be devised by the inspecting entity to document that a check is routinely done for Unintentional DC Grounds because of the possible consequences to the Protection System.

Where the standard refers to “all cells,” is it sufficient to have a documentation method that refers to “all cells,” or do we need to have separate documentation for every cell? For example, do I need 60 individual documented check-offs for good electrolyte level, or would a single check-off per bank be sufficient?

A single check-off per battery bank is sufficient for documentation, as long as the single check-off attests to checking all cells/units.

Does this standard refer to Station batteries or all batteries; for example, Communications Site Batteries?

This standard refers to Station Batteries. The drafting team does not believe that the scope of this standard refers to communications sites. The batteries covered under PRC-005-4 are the batteries that supply the trip current to the trip coils of the interrupting devices that are a part of the Protection System. The SDT believes that a loss of power to the communications systems at a remote site would cause the communications systems associated with protective relays to alarm at the substation. At this point, the corrective actions can be initiated.

What are cell/unit internal ohmic measurements?

With the introduction of Valve-Regulated Lead-Acid (VRLA) batteries to station dc supplies in the 1980’s several of the standard maintenance tools that are used on Vented Lead-Acid (VLA) batteries were unable to be used on this new type of lead-acid battery to determine its state of health. The only tools that were available to give indication of the health of these new VRLA batteries were voltage readings of the total battery voltage, the voltage of the individual cells and periodic discharge tests.

In the search for a tool for determining the health of a VRLA battery several manufacturers studied the electrical model of a lead acid battery’s current path through its cell. The overall battery current path consists of resistance and inductive and capacitive reactance. The inductive reactance in the current path through the battery is so minuscule when compared to the huge capacitive reactance of the cells that it is often ignored in most circuit models of the battery cell. Taking the basic model of a battery cell manufacturers of battery test equipment have developed and marketed testing devices to take measurements of the current path to detect degradation in the internal path through the cell.

In the battery industry, these various types of measurements are referred to as ohmic measurements. Terms used by the industry to describe ohmic measurements are ac conductance, ac impedance, and dc resistance. They are defined by the test equipment providers and IEEE and refer to the method of taking ohmic measurements of a lead acid battery. For example, in one manufacturer’s ac conductance equipment measurements are taken by applying a voltage of a known frequency and amplitude across a cell or battery unit and observing the ac current flow it produces in response to the voltage. A manufacturer of an ac impedance meter measures ac current of a known frequency and amplitude that is passed through the whole battery string and determines the impedances of each cell or unit by measuring the resultant ac

voltage drop across them. On the other hand, dc resistance of a cell is measured by a third manufacturer's equipment by applying a dc load across the cell or unit and measuring the step change in both the voltage and current to calculate the internal dc resistance of the cell or unit.

It is important to note that because of the rapid development of the market for ohmic measurement devices, there were no standards developed or used to mandate the test signals used in making ohmic measurements. Manufacturers using proprietary methods and applying different frequencies and magnitudes for their signals have developed a diversity of measurement devices. This diversity in test signals coupled with the three different types of ohmic measurements techniques (impedance conductance and resistance) make it impossible to always get the same ohmic measurement for a cell with different ohmic measurement devices. However, IEEE has recognized the great value for choosing one device for ohmic measurement, no matter who makes it or the method to calculate the ohmic measurement. The only caution given by IEEE and the battery manufacturers is that when trending the cells of a lead acid station battery consistent ohmic measurement devices should be used to establish the baseline measurement and to trend the battery set for its entire life.

For VRLA batteries both IEEE Standard 1188 (Maintenance, Testing and Replacement of VRLA Batteries) and IEEE Standard 1187 (Installation Design and Installation of VRLA Batteries) recognize the importance of the maintenance activity of establishing a baseline for "cell/unit internal ohmic measurements (impedance, conductance and resistance)" and trending them at frequent intervals over the life of the battery. There are extensive discussions about the need for taking these measurements in these standards. IEEE Standard 1188 requires taking internal ohmic values as described in Annex C4 during regular inspections of the station battery. For VRLA batteries IEEE Standard 1188 in talking about the necessity of establishing a baseline and trending it over time says, "…depending on the degree of change a performance test, cell replacement or other corrective action may be necessary…" (IEEE std 1188-2005, C.4 page 18).

For VLA batteries IEEE Standard 484 (Installation of VLA batteries) gives several guidelines about establishing baseline measurements on newly installed lead acid stationary batteries. The standard also discusses the need to look for significant changes in the ohmic measurements, the caution that measurement data will differ with each type of model of instrument used, and lists a number of factors that affect ohmic measurements.

At the beginning of the 21st century, EPRI conducted a series of extensive studies to determine the relationship of internal ohmic measurements to the capacity of a lead acid battery cell. The studies indicated that internal ohmic measurements were in fact a good indicator of a lead acid battery cell's capacity, but because users often were only interested in the total station battery capacity and the technology does not precisely predict overall battery capacity, if a user only needs "an accurate measure of the overall battery capacity," they should "perform a battery capacity test."

Prior to the EPRI studies some large and small companies which owned and maintained station dc supplies in NERC Protection Systems developed maintenance programs where trending of ohmic measurements of cells/units of the station's battery became the maintenance activity for determining if the station battery could perform as manufactured. By evaluation of the trending of the ohmic measurements over time, the owner could track the performance of the individual components of the station battery and determine if a total station battery or components of it

required capacity testing, removal, replacement or in many instances replacement of the entire station battery. By taking this condition based approach these owners have eliminated having to perform capacity testing at prescribed intervals to determine if a battery needs to be replaced and are still able to effectively determine if a station battery can perform as manufactured.

My VRLA batteries have multiple-cells within an individual battery jar (or unit); how am I expected to comply with the cell-to-cell ohmic measurement requirements on these units that I cannot get to?

Measurement of cell/unit (not all batteries allow access to "individual cells" some "units" or jars may have multiple cells within a jar) internal ohmic values of all types of lead acid batteries where the cells of the battery are not visible is a station dc supply maintenance activity in Table 1-4. In cases where individual cells in a multi-cell unit are inaccessible, an ohmic measurement of the entire unit may be made.

I have a concern about my batteries being used to support additional auxiliary loads beyond my protection control systems in a generation station. Is ohmic measurement testing sufficient for my needs?

While this standard is focused on addressing requirements for Protection Systems, if batteries are used to service other load requirements beyond that of Protection Systems (e.g. pumps, valves, inverter loads), the functional entity may consider additional testing to confirm that the capacity of the battery is sufficient to support all loads.

Why verify voltage?

There are two required maintenance activities associated with verification of dc voltages in Table 1-4. These two required activities are to verify station dc supply voltage and float voltage of the battery charger, and have different maximum maintenance intervals. Both of these voltage verification requirements relate directly to the battery charger maintenance.

The verification of the dc supply voltage is simply an observation of battery voltage to prove that the charger has not been lost or is not malfunctioning; a reading taken from the battery charger panel meter or even SCADA values of the dc voltage could be some of the ways that one could satisfy the requirements. Low battery voltage below float voltage indicates that the battery may be on discharge and, if not corrected, the station battery could discharge down to some extremely low value that will not operate the Protection System. High voltage, close to or above the maximum allowable dc voltage for equipment connected to the station dc supply indicates the battery charger may be malfunctioning by producing high dc voltage levels on the Protection System. If corrective actions are not taken to bring the high voltage down, the dc power supplies and other electronic devices connected to the station dc supply may be damaged. The maintenance activity of verifying the float voltage of the battery charger is not to prove that a charger is lost or producing high voltages on the station dc supply, but rather to prove that the charger is properly floating the battery within the proper voltage limits. As above, there are many ways that this requirement can be met.

Why check for the electrolyte level?

In vented lead-acid (VLA) and nickel-cadmium (NiCad) batteries the visible electrolyte level must be checked as one of the required maintenance activities that must be performed at an interval that is equal to or less than the maximum maintenance interval of Table 1-4. Because the electrolyte level in valve-regulated lead-acid (VRLA) batteries cannot be observed, there is no maintenance activity listed in Table 1-4 of the standard for checking the electrolyte level. Low

electrolyte level of any cell of a VLA or NiCad station battery is a condition requiring correction. Typically, the electrolyte level should be returned to an acceptable level for both types of batteries (VLA and NiCad) by adding distilled or other approved-quality water to the cell.

Often people confuse the interval for watering all cells required due to evaporation of the electrolyte in the station battery cells with the maximum maintenance interval required to check the electrolyte level. In many of the modern station batteries, the jar containing the electrolyte is so large with the band between the high and low electrolyte level so wide that normal evaporation which would require periodic watering of all cells takes several years to occur. However, because loss of electrolyte due to cracks in the jar, overcharging of the station battery, or other unforeseen events can cause rapid loss of electrolyte; the shorter maximum maintenance intervals for checking the electrolyte level are required. A low level of electrolyte in a VLA battery cell which exposes the tops of the plates can cause the exposed portion of the plates to accelerated sulfation resulting in loss of cell capacity. Also, in a VLA battery where the electrolyte level goes below the end of the cell withdrawal tube or filling funnel, gasses can exit the cell by the tube instead of the flame arrester and present an explosion hazard.

What are the parameters that can be evaluated in Tables 1-4(a) and 1-4(b)?

The most common parameter that is periodically trended and evaluated by industry today to verify that the station battery can perform as manufactured is internal ohmic cell/unit measurements.

In the mid-1990s, several large and small utilities began developing maintenance and testing programs for Protection System station batteries using a condition based maintenance approach of trending internal ohmic measurements to each station battery cell's baseline value. Battery owners use the data collected from this maintenance activity to determine (1) when a station battery requires a capacity test (instead of performing a capacity test on a predetermined, prescribed interval), (2) when an individual cell or battery unit should be replaced, or (3) based on the analysis of the trended data, if the station battery should be replaced without performing a capacity test.

Other examples of measurable parameters that can be periodically trended and evaluated for lead acid batteries are cell voltage, float current, connection resistance. However, periodically trending and evaluating cell/unit Ohmic measurements are the most common battery/cell parameters that are evaluated by industry to verify a lead acid battery string can perform as manufactured.

Why does it appear that there are two maintenance activities in Table 1-4(b) (for VRLA batteries) that appear to be the same activity and have the same maximum maintenance interval?

There are two different and distinct reasons for doing almost the same maintenance activity at the same interval for valve-regulated lead-acid (VRLA) batteries. The first similar activity for VRLA batteries (Table 1-4(b)) that has the same maximum maintenance interval is to "measure battery cell/unit internal ohmic values." Part of the reason for this activity is because the visual inspection of the cell condition is unavailable for VRLA batteries. Besides the requirement to measure the internal ohmic measurements of VRLA batteries to determine the internal health of the cell, the maximum maintenance interval for this activity is significantly shorter than the interval for vented lead-acid (VLA) due to some unique failure modes for VRLA batteries. Some

of the potential problems that VRLA batteries are susceptible to that do not affect VLA batteries are thermal runaway, cell dry-out, and cell reversal when one cell has a very low capacity.

The other similar activity listed in Table 1-4(b) is "…verify that the station battery can perform as manufactured by evaluating the measured cell/unit measurements indicative of battery performance (e.g. internal ohmic values) against the station battery baseline." This activity allows an owner the option to choose between this activity with its much shorter maximum maintenance interval or the longer maximum maintenance interval for the maintenance activity to "Verify that the station battery can perform as manufactured by conducting a performance or modified performance capacity test of the entire battery bank."

For VRLA batteries, there are two drivers for internal ohmic readings. The first driver is for a means to trend battery life. Trending against the baseline of VRLA cells in a battery string is essential to determine the approximate state of health of the battery. Ohmic measurement testing may be used as the mechanism for measuring the battery cells. If all the cells in the string exhibit a consistent trend line and that trend line has not risen above a specific deviation (e.g. 30%) over baseline for impedance tests or below baseline for conductance tests, then a judgment can be made that the battery is still in a reasonably good state of health and able to 'perform as manufactured.' It is essential that the specific deviation mentioned above is based on data (test or otherwise) that correlates the ohmic readings for a specific battery/tester combination to the health of the battery. This is the intent of the "perform **as** manufactured six-month test" at Row 4 on Table 1-4b.

The second big driver is VRLA batteries tendency for thermal runaway. This is the intent of the "thermal runaway test" at Row 2 on Table 1-4b. In order to detect a cell in thermal runaway, you need not necessarily have a formal trending program. When a single cell/unit changes significantly or significantly varies from the other cells (e.g. a doubling of resistance/impedance or a 50% decrease in conductance), there is a high probability that the cell/unit/string needs to be replaced as soon as possible. In other words, if the battery is 10 years old and all the cells have approached a significant change in ohmic values over baseline, then you have a battery which is approaching end of life. You need to get ready to buy a new battery, but you do not have to worry about an impending catastrophic failure. On the other hand, if the battery is five years old and you have one cell that has a markedly different ohmic reading than all the other cells, then you need to be worried that this cell is susceptible to thermal runaway. If the float (charging) current has risen significantly and the ohmic measurement has increased/decreased as described above then concern of catastrophic failure should trigger attention for corrective action.

If an entity elects to use a capacity test rather than a cell ohmic value trending program, this does not eliminate the need to be concerned about thermal runaway – the entity still needs to do the six-month readings and look for cells which are outliers in the string but they need not trend results against the factory/as new baseline. Some entities will not mind the extra administrative burden of having the ongoing trending program against baseline - others would rather just do the capacity test and not have to trend the data against baseline. Nonetheless, all entities must look for ohmic outliers on a six-month basis.

It is possible to accomplish both tasks listed (trend testing for capability and testing for thermal runaway candidates) with the very same ohmic test. It becomes an analysis exercise of watching the trend from baselines and watching for the oblique cell measurement.

In table 1-4(f) (Exclusions for Protection System Station dc Supply Monitoring Devices and Systems), must all component attributes listed in the table be met before an exclusion can be granted for a maintenance activity?

Table 1-4(f) was created by the drafting team to allow Protection System dc supply owners to obtain exclusions from periodic maintenance activities by using monitoring devices. The basis of the exclusions granted in the table is that the monitoring devices must incorporate the monitoring capability of microprocessor based components which perform continuous self-monitoring. For failure of the microprocessor device used in dc supply monitoring, the self-checking routine in the microprocessor must generate an alarm which will be reported within 24 hours of device failure to a location where corrective action can be initiated.

Table 1-4(f) lists 8 component attributes along with a specific periodic maintenance activity associated with each of the 8 attributes listed. If an owner of a station dc supply wants to be excluded from periodically performing one of the 8 maintenance activities listed in table 1-4(f), the owner must have evidence that the monitoring and alarming component attributes associated with the excluded maintenance activity are met by the self-checking microprocessor based device with the specific component attribute listed in the table 1-4(f).

For example if an owner of a VLA station battery does not want to "verify station dc supply voltage" every "4 calendar months" (see table 1-4(a)), the owner can install a monitoring and alarming device "with high and low voltage monitoring and alarming of the battery charger voltage to detect charger overvoltage and charger failure" and "no periodic verification of station dc supply voltage is required" (see table 1-4(f) first row). However, if for the same Protection System discussed above, the owner does not install "electrolyte level monitoring and alarming in every cell" and "unintentional dc ground monitoring and alarming" (see second and third rows of table 1-4(f)), the owner will have to "inspect electrolyte level and for unintentional grounds" every "4 calendar months" (see table 1-4(a)).

15.5 Associated communications equipment (Table 1-2)

The equipment used for tripping in a communications-assisted trip scheme is a vital piece of the trip circuit. Remote action causing a local trip can be thought of as another parallel trip path to the trip coil that must be tested. Besides the trip output and wiring to the trip coil(s), there is also a communications medium that must be maintained. Newer technologies now exist that achieve communications-assisted tripping without the conventional wiring practices of older technology. For example, older technologies may have included Frequency Shift Key methods. This technology requires that guard and trip levels be maintained. The actual tripping path(s) to the trip coil(s) may be tested as a parallel trip path within the dc control circuitry tests. Emerging technologies transfer digital information over a variety of carrier mediums that are then interpreted locally as trip signals. The requirements apply to the communicated signal needed for the proper operation of the protective relay trip logic or scheme. Therefore, this standard is applied to equipment used to convey both trip signals (permissive or direct) and block signals.

It was the intent of this standard to require that a test be performed on any communications-assisted trip scheme, regardless of the vintage of technology. The essential element is that the tripping (or blocking) occurs locally when the remote action has been asserted; or that the tripping (or blocking) occurs remotely when the local action is asserted. Note that the required testing can still be done within the concept of testing by overlapping segments. Associated communications equipment can be (but is not limited to) testing at other times and different frequencies as the protective relays, the individual trip paths and the affected circuit interrupting devices.

Some newer installations utilize digital signals over fiber-optics from the protective relays in the control house to the circuit interrupting device in the yard. This method of tripping the circuit breaker, even though it might be considered communications, must be maintained per the dc control circuitry maintenance requirements.

15.5.1 Frequently Asked Questions:

What are some examples of mechanisms to check communications equipment functioning?

For unmonitored Protection Systems, various types of communications systems will have different facilities for on-site integrity checking to be performed at least every four months during a substation visit. Some examples are, but not limited to:

- On-off power-line carrier systems can be checked by performing a manual carrier keying test between the line terminals, or carrier check-back test from one terminal.
- Systems which use frequency-shift communications with a continuous guard signal (over a telephone circuit, analog microwave system, etc.) can be checked by observing for a loss-of-guard indication or alarm. For frequency-shift power-line carrier systems, the guard signal level meter can also be checked.
- Hard-wired pilot wire line Protection Systems typically have pilot-wire monitoring relays that give an alarm indication for a pilot wire ground or open pilot wire circuit loop.
- Digital communications systems typically have a data reception indicator or data error indicator (based on loss of signal, bit error rate, or frame error checking).

For monitored Protection Systems, various types of communications systems will have different facilities for monitoring the presence of the communications channel, and activating alarms that can be monitored remotely. Some examples are, but not limited to:

- On-off power-line carrier systems can be shown to be operational by automated periodic power-line carrier check-back tests with remote alarming of failures.
- Systems which use a frequency-shift communications with a continuous guard signal (over a telephone circuit, analog microwave system, etc.) can be remotely monitored with a loss-of-guard alarm or low signal level alarm.
- Hard-wired pilot wire line Protection Systems can be monitored by remote alarming of pilot-wire monitoring relays.
- Digital communications systems can activate remotely monitored alarms for data reception loss or data error indications.
- Systems can be queried for the data error rates.

For the highest degree of monitoring of Protection Systems, the communications system must monitor all aspects of the performance and quality of the channel that show it meets the design performance criteria, including monitoring of the channel interface to protective relays.

- In many communications systems signal quality measurements, including signal-to-noise ratio, received signal level, reflected transmitter power or standing wave ratio, propagation delay, and data error rates are compared to alarm limits. These alarms are connected for remote monitoring.
- Alarms for inadequate performance are remotely monitored at all times, and the alarm communications system to the remote monitoring site must itself be continuously

monitored to assure that the actual alarm status at the communications equipment location is continuously being reflected at the remote monitoring site.

What is needed for the four-month inspection of communications-assisted trip scheme equipment?

The four-month inspection applies to unmonitored equipment. An example of compliance with this requirement might be, but is not limited to:

With each site visit, check that the equipment is free from alarms; check any metered signal levels, and that power is still applied. While this might be explicit for a particular type of equipment (i.e., FSK equipment), the concept should be that the entity verify that the communications equipment that is used in a Protection System is operable through a cursory inspection and site visit. This site visit can be eliminated on this particular example if the FSK equipment had a monitored alarm on Loss of Guard. Blocking carrier systems with auto checkbacks will present an alarm when the channel fails allowing a visual indication. With no auto checkback, the channel integrity will need to be verified by a manual checkback or a two ended signal check. This check could also be eliminated by bring the auto checkback failure alarm to the monitored central location.

Does a fiber optic I/O scheme used for breaker tripping or control within a station, for example - transmitting a trip signal or control logic between the control house and the breaker control cabinet, constitute a communications system?

This equipment is presently classified as being part of the Protection System control circuitry and tested per the portions of Table 1 applicable to “Protection System Control Circuitry”, rather than those portions of the table applicable to communications equipment.

What is meant by “Channel” and “Communications Systems” in Table 1-2?

The transmission of logic or data from a relay in one station to a relay in another station for use in a pilot relay scheme will require a communications system of some sort. Typical relay communications systems use fiber optics, leased audio channels, power line carrier, and microwave. The overall communications system includes the channel and the associated communications equipment.

This standard refers to the “channel” as the medium between the transmitters and receivers in the relay panels such as a leased audio or digital communications circuit, power line and power line carrier auxiliary equipment, and fiber. The dividing line between the channel and the associated communications equipment is different for each type of media.

Examples of the Channel:

- Power Line Carrier (PLC) - The PLC channel starts and ends at the PLC transmitter and receiver output unless there is an internal hybrid. The channel includes the external hybrids, tuners, wave traps and the power line itself.
- Microwave –The channel includes the microwave multiplexers, radios, antennae and associated auxiliary equipment. The audio tone and digital transmitters and receivers in the relay panel are the associated communications equipment.
- Digital/Audio Circuit – The channel includes the equipment within and between the substations. The associated communications equipment includes the relay panel transmitters and receivers and the interface equipment in the relays.

- Fiber Optic – The channel starts at the fiber optic connectors on the fiber distribution panel at the local station and goes to the fiber optic distribution panel at the remote substation. The jumpers that connect the relaying equipment to the fiber distribution panel and any optical-electrical signal format converters are the associated communications equipment

Figure 1-2, A-1 and A-2 at the end of this document show good examples of the communications channel and the associated communications equipment.

In Table 1-2, the Maintenance Activities section of the Protection System Communications Equipment and Channels refers to the quality of the channel meeting "performance criteria." What is meant by performance criteria?

Protection System communications channels must have a means of determining if the channel and communications equipment is operating normally. If the channel is not operating normally, an alarm will be indicated. For unmonitored systems, this alarm will probably be on the panel. For monitored systems, the alarm will be transmitted to a remote location.

Each entity will have established a nominal performance level for each Protection System communications channel that is consistent with proper functioning of the Protection System. If that level of nominal performance is not being met, the system will go into alarm. Following are some examples of Protection System communications channel performance measuring:

- For direct transfer trip using a frequency shift power line carrier channel, a guard level monitor is part of the equipment. A normal receive level is established when the system is calibrated and if the signal level drops below an established level, the system will indicate an alarm.
- An on-off blocking signal over power line carrier is used for directional comparison blocking schemes on transmission lines. During a Fault, block logic is sent to the remote relays by turning on a local transmitter and sending the signal over the power line to a receiver at the remote end. This signal is normally off so continuous levels cannot be checked. These schemes use check-back testing to determine channel performance. A predetermined signal sequence is sent to the remote end and the remote end decodes this signal and sends a signal sequence back. If the sending end receives the correct information from the remote terminal, the test passes and no alarm is indicated. Full power and reduced power tests are typically run. Power levels for these tests are determined at the time of calibration.
- Pilot wire relay systems use a hardwire communications circuit to communicate between the local and remote ends of the protective zone. This circuit is monitored by circulating a dc current between the relay systems. A typical level may be 1 mA. If the level drops below the setting of the alarm monitor, the system will indicate an alarm.
- Modern digital relay systems use data communications to transmit relay information to the remote end relays. An example of this is a line current differential scheme commonly used on transmission lines. The protective relays communicate current magnitude and phase information over the communications path to determine if the Fault is located in

the protective zone. Quantities such as digital packet loss, bit error rate and channel delay are monitored to determine the quality of the channel. These limits are determined and set during relay commissioning. Once set, any channel quality problems that fall outside the set levels will indicate an alarm.

The previous examples show how some protective relay communications channels can be monitored and how the channel performance can be compared to performance criteria established by the entity. This standard does not state what the performance criteria will be; it just requires that the entity establish nominal criteria so Protection System channel monitoring can be performed.

How is the performance criteria of Protection System communications equipment involved in the maintenance program?

An entity determines the acceptable performance criteria, depending on the technology implemented. If the communications channel performance of a Protection System varies from the pre-determined performance criteria for that system, then these results should be investigated and resolved.

How do I verify the A/D converters of microprocessor-based relays?

There are a variety of ways to do this. Two examples would be: using values gathered via data communications and automatically comparing these values with values from other sources, or using groupings of other measurements (such as vector summation of bus feeder currents) for comparison. Many other methods are possible.

15.6 Alarms (Table 2)

In addition to the tables of maintenance for the components of a Protection System, there is an additional table added for alarms. This additional table was added for clarity. This enabled the common alarm attributes to be consolidated into a single spot, and, thus, make it easier to read the Tables 1-1 through 1-5, Table 3, and Table 4. The alarms need to arrive at a site wherein a corrective action can be initiated. This could be a control room, operations center, etc. The alarming mechanism can be a standard alarming system or an auto-polling system; the only requirement is that the alarm be brought to the action-site within 24 hours. This effectively makes manned-stations equivalent to monitored stations. The alarm of a monitored point (for example a monitored trip path with a lamp) in a manned-station now makes that monitored point eligible for monitored status. Obviously, these same rules apply to a non-manned-station, which is that if the monitored point has an alarm that is auto-reported to the operations center (for example) within 24 hours, then it too is considered monitored.

15.6.1 Frequently Asked Questions:

Why are there activities defined for varying degrees of monitoring a Protection System component when that level of technology may not yet be available?

There may already be some equipment available that is capable of meeting the highest levels of monitoring criteria listed in the Tables. However, even if there is no equipment available today that can meet this level of monitoring the standard establishes the necessary requirements for when such equipment becomes available. By creating a roadmap for development, this provision makes the standard technology neutral. The Standard Drafting Team wants to avoid the need to revise the standard in a few years to accommodate technology advances that may be coming to the industry.

Does a fail-safe "form b" contact that is alarmed to a 24/7 operation center classify as an alarm path with monitoring?

If the fail-safe "form-b" contact that is alarmed to a 24/7 operation center causes the alarm to activate for failure of any portion of the alarming path from the alarm origin to the 24/7 operations center, then this can be classified as an alarm path with monitoring.

15.7 Distributed UFLS and Distributed UVLS Systems (Table 3)

Distributed UFLS and distributed UVLS systems have their maintenance activities documented in Table 3 due to their distributed nature allowing reduced maintenance activities and extended maximum maintenance intervals. Relays have the same maintenance activities and intervals as Table 1-1. Voltage and current-sensing devices have the same maintenance activity and interval as Table 1-3. DC systems need only have their voltage read at the relay every 12 years. Control circuits have the following maintenance activities every 12 years:

- Verify the trip path between the relay and lock-out and/or auxiliary tripping device(s).
- Verify operation of any lock-out and/or auxiliary tripping device(s) used in the trip circuit.
- No verification of trip path required between the lock-out (and/or auxiliary tripping device) and the non-BES interrupting device.
- No verification of trip path required between the relay and trip coil for circuits that have no lock-out and/or auxiliary tripping device(s).
- No verification of trip coil required.

No maintenance activity is required for associated communication systems for distributed UFLS and distributed UVLS schemes.

Non-BES interrupting devices that participate in a distributed UFLS or distributed UVLS scheme are excluded from the tripping requirement, and part of the control circuit test requirement; however, the part of the trip path control circuitry between the Load-Shed relay and lock-out or auxiliary tripping relay must be tested at least once every 12 years. In the case where there is no lock-out or auxiliary tripping relay used in a distributed UFLS or UVLS scheme which is not part of the BES, there is no control circuit test requirement. There are many circuit interrupting devices in the distribution system that will be operating for any given under-frequency event that requires tripping for that event. A failure in the tripping action of a single distributed system circuit breaker (or non-BES equipment interruption device) will be far less significant than, for example, any single transmission Protection System failure, such as a failure of a bus differential lock-out relay. While many failures of these distributed system circuit breakers (or non-BES equipment interruption device) could add up to be significant, it is also believed that many circuit breakers are operated often on just Fault clearing duty; and, therefore, these circuit breakers are operated at least as frequently as any requirements that appear in this standard.

There are times when a Protection System component will be used on a BES device, as well as a non-BES device, such as a battery bank that serves both a BES circuit breaker and a non-BES interrupting device used for UFLS. In such a case, the battery bank (or other Protection System component) will be subject to the Tables of the standard because it is used for the BES.

15.7.1 Frequently Asked Questions:

The standard reaches further into the distribution system than we would like for UFLS and UVLS

While UFLS and UVLS equipment are located on the distribution network, their job is to protect the Bulk Electric System. This is not beyond the scope of NERC's 215 authority.

FPA section 215(a) definitions section defines bulk power system as: "(A) facilities and control Systems necessary for operating an interconnected electric energy transmission network (or any portion thereof)." That definition, then, is limited by a later statement which adds the term bulk power system "…does not include facilities used in the local distribution of electric energy." Also, Section 215 also covers users, owners, and operators of bulk power Facilities.

UFLS and UVLS (when the UVLS is installed to prevent system voltage collapse or voltage instability for BES reliability) are not "used in the local distribution of electric energy," despite their location on local distribution networks. Further, if UFLS/UVLS Facilities were not covered by the reliability standards, then in order to protect the integrity of the BES during under-frequency or under-voltage events, that Load would have to be shed at the Transmission bus to ensure the Load-generation balance and voltage stability is maintained on the BES.

15.8 Automatic Reclosing (Table 4)

Please see the document referenced in Section F of PRC-005-3, "Considerations for Maintenance and Testing of Autoreclosing Schemes — November 2012", for a discussion of Automatic Reclosing as addressed in PRC-005-3.

15.8.1 Frequently-asked Questions

Automatic Reclosing is a control, not a protective function; why then is Automatic Reclosing maintenance included in the Protection System Maintenance Program (PSMP)?

Automatic Reclosing is a control function. The standard's title 'Protection System and Automatic Reclosing Maintenance' clearly distinguishes (separates) the Automatic Reclosing from the Protection System. Automatic Reclosing is included in the PSMP because it is a more pragmatic approach as compared to creating a parallel and essentially identical 'Control System Maintenance Program' for the two Automatic Reclosing component types.

When do I need to have the initial maintenance of Automatic Reclosing Components completed upon change of the largest BES generating unit in the BA/RSG?

The maintenance interval, for newly identified Automatic Reclosing Components, starts when a change in the largest BES generating unit is determined by the BA/RSG. The first maintenance records for newly identified Automatic Reclosing Components should be dated no later than the maximum maintenance interval after the identification date. The maximum maintenance intervals for each newly identified Component are defined in Table 4. No activities or records are required prior to the date of identification.

Our maintenance practice consists of initiating the Automatic Reclosing relay and confirming the breaker closes properly and the close signal is released. This practice verifies the control circuitry associated with Automatic Reclosing. Do you agree?"

The described task partially verifies the control circuit maintenance activity. To meet the control circuit maintenance activity, responsible entities need to verify, *upon initiation*, that the reclosing relay does not issue a *premature closing command*. As noted on page 12 of the SAMS/SPCS report, the concern being addressed within the standard is premature auto reclosing that has the potential to cause generating unit or plant instability. Reclosing applications have many variations, responsible entities will need to verify the applicability of associated supervision/conditional logic and the reclosing relay operation; then verify the conditional logic or that the reclosing relay performs in a manner that does not result in a *premature closing command* being issued.

Some examples of conditions which can result in a premature closing command are: an improper supervision or conditional logic input which provides a false state and allows the reclosing relay to issue an improper close command based on incorrect conditions (i.e. voltage supervision, equipment status, sync window verification); timers utilized for closing actuation or reclosing arming/disarming circuitry which could allow the reclosing relay to issue an improper close command; a reclosing relay output contact failure which could result in a made-up-close condition / failure-to-release condition.

Why was a close-in three phase fault present for twice the normal clearing time chosen for the Automatic Reclosing exclusion? It exceeds TPL requirements and ignores the breaker closing time in a trip-close-trip sequence, thus making the exclusion harder to attain.

This condition represents a situation where a close signal is issued with no time delay or with less time delay than is intended, such as if a reclosing contact is welded closed. This failure mode can result in a minimum trip-close-trip sequence with the two faults cleared in primary protection operating time, and the open time between faults equal to the breaker closing cycle time. The sequence for this failure mode results in system impact equivalent to a high-speed autoreclosing sequence with no delay added in the autoreclosing logic. It represents a failure mode which must be avoided because it exceeds TPL requirements.

Do we have to test the various breaker closing circuit interlocks and controls such as anti-pump?

These components are not specifically addressed within Table 4, and need not be individually tested. They are indirectly verified by performing the Automatic Reclosing control circuitry verification as established in Table 4.

For Automatic Reclosing that is not part of an RAS, do we have to close the circuit breaker periodically?

No. For this application, you need only to verify that the Automatic Reclosing, upon initiation, does not issue a premature closing command. This activity is concerned only with assuring that a premature close does not occur, and cause generating plant instability.

For Automatic Reclosing that is part of an RAS, do we have to close the circuit breaker periodically?

Yes. In this application, successful closing is a necessary portion of the RAS, and must be verified.

15.9 Sudden Pressure Relaying (Table 5)

Please see the document referenced in Section F of PRC-005-4, "Sudden Pressure Relays and Other Devices that Respond to Non-Electrical Quantities – December 2013", for a discussion of Sudden Pressure Relaying as addressed in PRC-005-4.

15.9.1 Frequently Asked Questions:

How do I verify the pressure or flow sensing mechanism is operable?

Maintenance activities for the fault pressure relay associated with Sudden Pressure Relaying in PRC-005-4 are intended to verify that the pressure and/or flow sensing mechanism are functioning correctly. Beyond this, PRC-005-4 requires no calibration (adjusting the operating threshold or measurement accuracy of a measuring element to meet the intended performance requirement) or testing (applying signals to a component to observe functional performance or output behavior, or to diagnose problems) activities. For example, some designs of flow sensing mechanisms allow the operation of a test switch to actuate the limit switch of the flow sensing mechanism. Operation of this test switch and verification of the flow sensing mechanism would meet the requirements of the maintenance activity. Another example involves a gas pressure sensing mechanism which is isolated by a test plug. Removal of the plug and verification of the bellows mechanism would meet the requirements of the maintenance activity.

Why the 6-year maximum maintenance interval for fault pressure relays?

The SDT established the six-year maintenance interval for fault pressure relays (see Table 5, PRC-005-4) based on the recommendation of the System Protection and Control Subcommittee (SPCS). The technical experts of the SPCS were tasked with developing the technical documents to:

i. Describe the devices and functions (to include sudden pressure relays which trip for fault conditions) that should address FERC's concern; and

ii. Propose minimum maintenance activities for such devices and maximum maintenance intervals, including the technical basis for each.

Excerpt from the SPCS technical report: "In order to determine present industry practices related to sudden pressure relay maintenance, the SPCS conducted a survey of Transmission Owners and Generator Owners in all eight Regions requesting information related to their maintenance practices. The SPCS received responses from 75 Transmission Owners and 109 Generator Owners. Note that, for the purpose of the survey, sudden pressure relays included the following: the "sudden pressure relay" (SPR) originally manufactured by Westinghouse, the "rapid pressure rise relay" (RPR) manufactured by Qualitrol, and a variety of Buchholz relays.

Table 2 provides a summary of the results of the responses:

Table 2: Sudden Pressure Relay Maintenance Practices – Survey Results		
	Transmission Owner	**Generator Owner**
Number of responding owners that trip with Sudden Pressure Relays:	67	84

Percentage of responding owners who trip that have a Maintenance Program:	75%	78%
Percentage of maintenance programs that include testing the pressure actuator:	81%	77%
Average Maintenance interval reported:	5.9 years	4.9 years

Additionally, in order to validate the information noted above, the SPCS contacted the following entities for their feedback: the IEEE Power System Relaying Committee, the IEEE Transformer Committee, the Doble Transformer Committee, the NATF System Protection Practices Group, and the EPRI Generator Owner/Operator Technical Focus Group. All of these organizations indicated the results of the SPCS survey are consistent with their respective experiences.

The SPCS discussed the potential difference between the recommended intervals for fault pressure relaying and intervals for transformer maintenance. The SPCS developed the recommended intervals for fault pressure relaying by comparing fault pressure relaying to Protection System Components with similar physical attributes. The SPCS recognized that these intervals may be shorter than some existing or future transformer maintenance intervals, but believed it to be more important to base intervals for fault pressure relaying on similar Protection System Components than transformer maintenance intervals.

The maintenance interval for fault pressure relays can be extended by utilizing performance-based maintenance thereby allowing entities that have maintenance intervals for transformers in excess of six years, to align them.

Sudden Pressure Relaying control circuitry is now specifically mentioned in the maintenance tables. Do we have to trip our circuit breaker specifically from the trip output of the sudden pressure relay?

No. Verification may be by breaker tripping, but may be verified in overlapping segments with the Protection System control circuitry.

Can we use Performance Based Maintenance for fault pressure relays?

Yes. Performance Based Maintenance is applicable to fault pressure relays.

15.10 Examples of Evidence of Compliance

To comply with the requirements of this standard, an entity will have to document and save evidence. The evidence can be of many different forms. The Standard Drafting Team recognizes that there are concurrent evidence requirements of other NERC standards that could, at times, fulfill evidence requirements of this standard.

15.10.1 Frequently Asked Questions:

What forms of evidence are acceptable?

Acceptable forms of evidence, as relevant for the requirement being documented include, but are not limited to:

- Process documents or plans

- Data (such as relay settings sheets, photos, SCADA, and test records)
- Database lists, records and/or screen shots that demonstrate compliance information
- Prints, diagrams and/or schematics
- Maintenance records
- Logs (operator, substation, and other types of log)
- Inspection forms
- Mail, memos, or email proving the required information was exchanged, coordinated, submitted or received
- Check-off forms (paper or electronic)
- Any record that demonstrates that the maintenance activity was known, accounted for, and/or performed.

If I replace a failed Protection System component with another component, what testing do I need to perform on the new component?

In order to reset the Table 1 maintenance interval for the replacement component, all relevant Table 1 activities for the component should be performed.

I have evidence to show compliance for PRC-016 ("Special Protection System Misoperation"). Can I also use it to show compliance for this Standard, PRC-005-4?

Maintaining evidence for operation of Remedial Action Schemes could concurrently be utilized as proof of the operation of the associated trip coil (provided one can be certain of the trip coil involved). Thus, the reporting requirements that one may have to do for the Misoperation of a Special Protection Scheme under PRC-016 could work for the activity tracking requirements under this PRC-005-4.

I maintain Disturbance records which show Protection System operations. Can I use these records to show compliance?

These records can be concurrently utilized as dc trip path verifications, to the degree that they demonstrate the proper function of that dc trip path.

I maintain test reports on some of my Protection System components. Can I use these test reports to show that I have verified a maintenance activity?

Yes.

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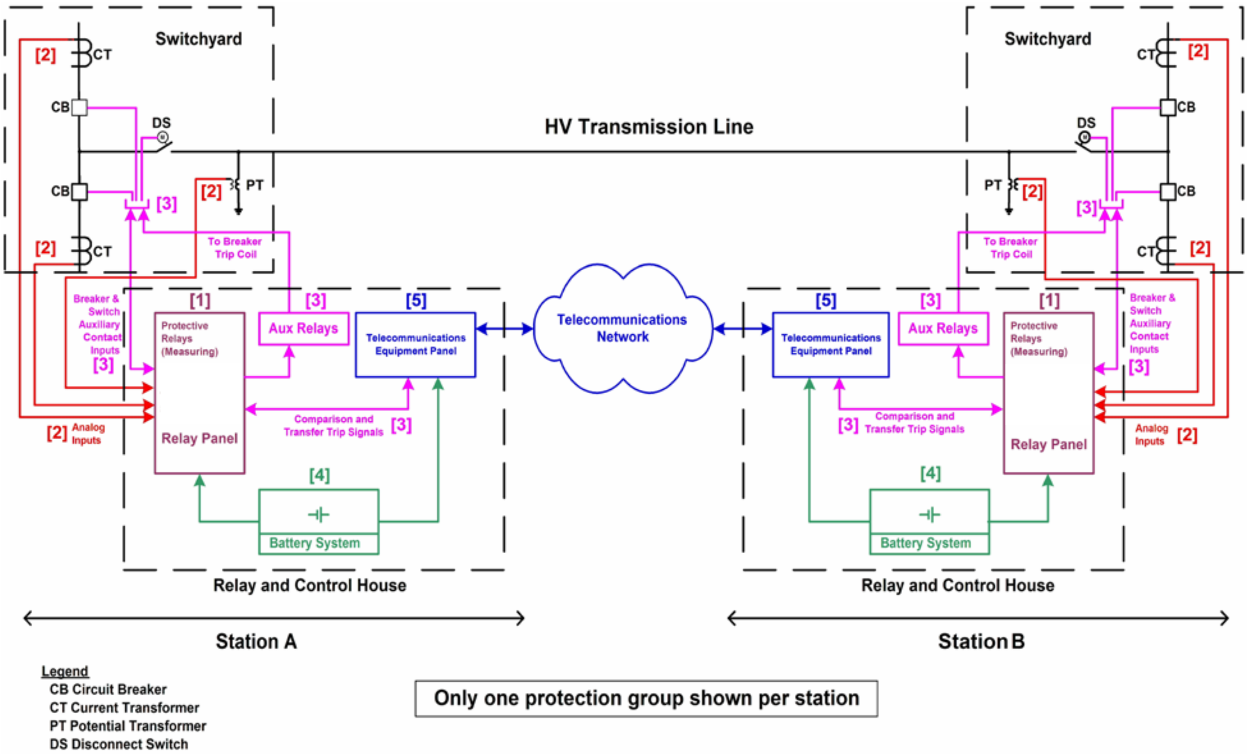
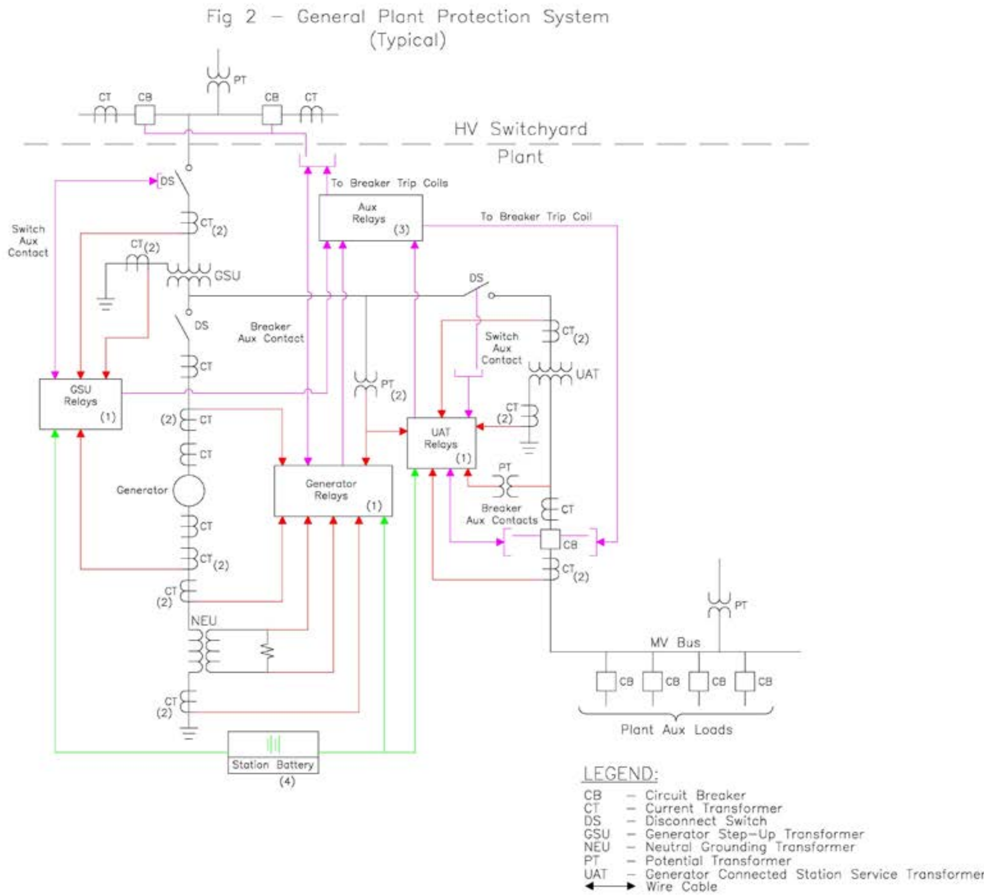
Figures

Figure 1: Typical Transmission System



For information on components, see ***Figure 1 & 2 Legend – components of Protection Systems***

Figure 2: Typical Generation System



Note: Figure 2 may show elements that are not included within PRC-005-2, and also may not be all-inclusive; see the Applicability section of the standard for specifics.

For information on components, see ***Figure 1 & 2 Legend – components of Protection Systems***

Figure 1 & 2 Legend – Components of Protection Systems

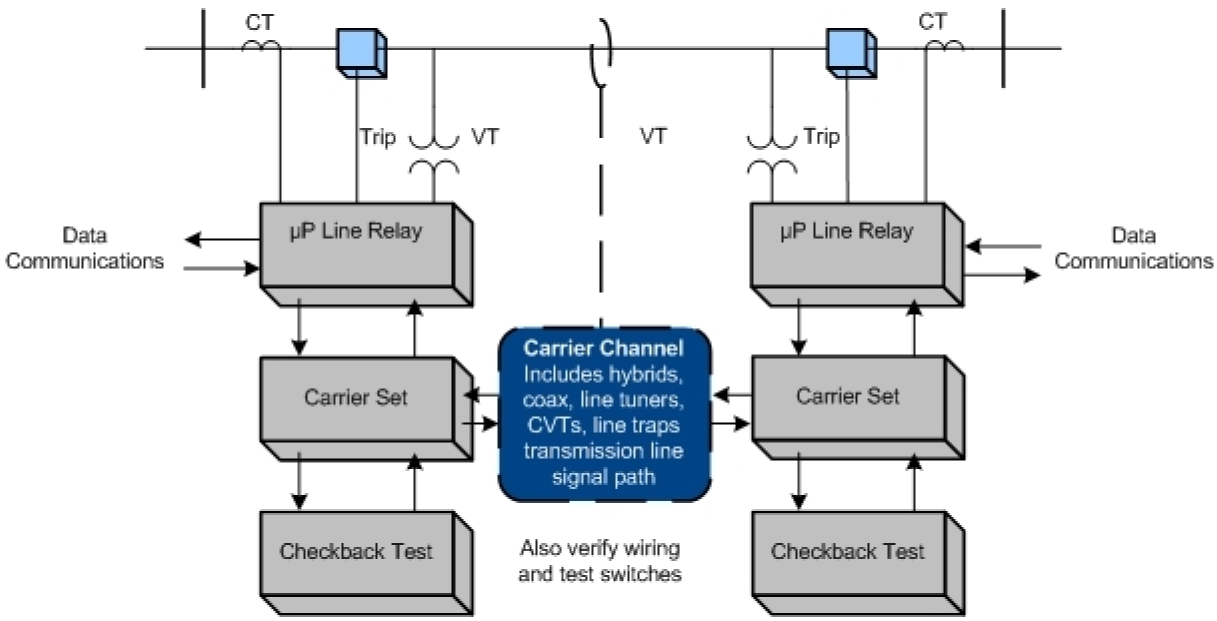
Number in Figure	Component of Protection System	Includes	Excludes
1	Protective relays which respond to electrical quantities	All protective relays that use current and/or voltage inputs from current & voltage sensors and that trip the 86, 94 or trip coil.	Devices that use non-electrical methods of operation including thermal, pressure, gas accumulation, and vibration. Any ancillary equipment not specified in the definition of Protection Systems. Control and/or monitoring equipment that is not a part of the automatic tripping action of the Protection System
2	Voltage and current sensing devices providing inputs to protective relays	The signals from the voltage & current sensing devices to the protective relay input.	Voltage & current sensing devices that are not a part of the Protection System, including sync-check systems, metering systems and data acquisition systems.
3	Control circuitry associated with protective functions	All control wiring (or other medium for conveying trip signals) associated with the tripping action of 86 devices, 94 devices or trip coils (from all parallel trip paths). This would include fiber-optic systems that carry a trip signal as well as hard-wired systems that carry trip current.	Closing circuits, SCADA circuits, other devices in control scheme not passing trip current
4	Station dc supply	Batteries and battery chargers and any control power system which has the function of supplying power to the protective relays, associated trip circuits and trip coils.	Any power supplies that are not used to power protective relays or their associated trip circuits and trip coils.
5	Communications systems necessary for correct operation of protective functions	Tele-protection equipment used to convey specific information, in the form of analog or digital signals, necessary for the correct operation of protective functions.	Any communications equipment that is not used to convey information necessary for the correct operation of protective functions.

Additional information can be found in References

Appendix A

The following illustrates the concept of overlapping verifications and tests as summarized in Section 10 of the paper. As an example, Figure A-1 shows protection for a critical transmission line by carrier blocking directional comparison pilot relaying. The goal is to verify the ability of the entire two-terminal pilot protection scheme to protect for line Faults, and to avoid over-tripping for Faults external to the transmission line zone of protection bounded by the current transformer locations.

Figure A-1



In this example (Figure A1), verification takes advantage of the self-monitoring features of microprocessor multifunction line relays at each end of the line. For each of the line relays themselves, the example assumes that the user has the following arrangements in place:

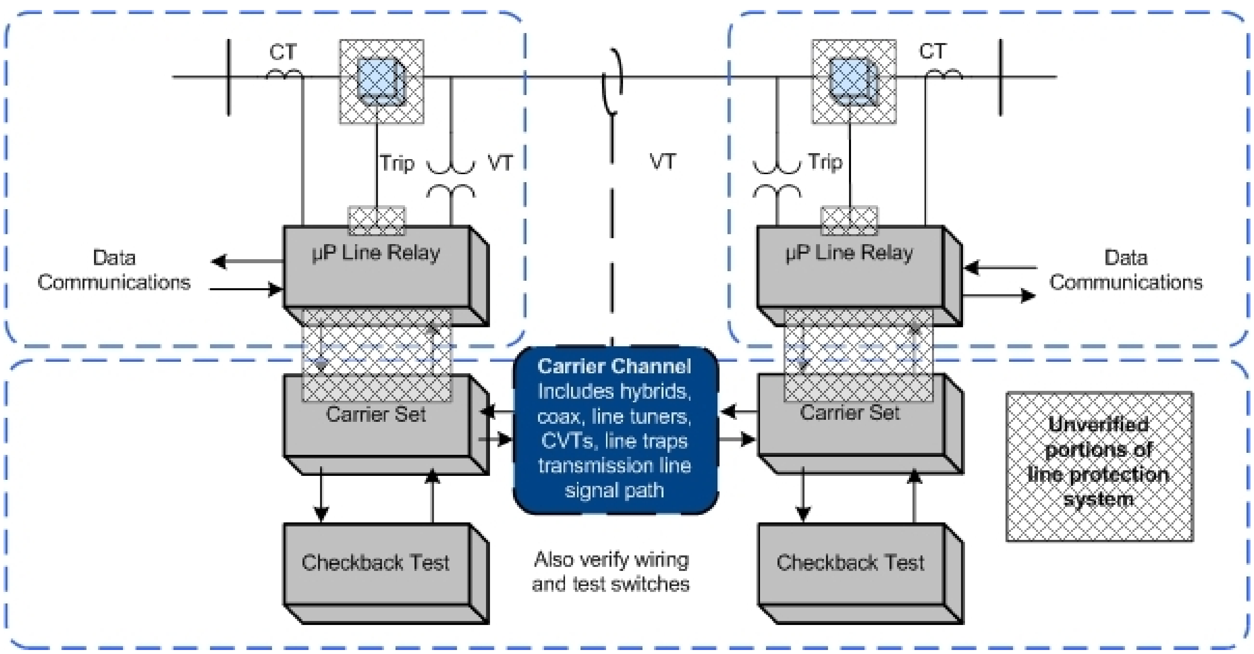
1. The relay has a data communications port that can be accessed from remote locations.
2. The relay has internal self-monitoring programs and functions that report failures of internal electronics, via communications messages or alarm contacts to SCADA.
3. The relays report loss of dc power, and the relays themselves or external monitors report the state of the dc battery supply.
4. The CT and PT inputs to the relays are used for continuous calculation of metered values of volts, amperes, plus Watts and VARs on the line. These metered values are reported by data communications. For maintenance, the user elects to compare these readings to those of other relays, meters, or DFRs. The other readings may be from redundant relaying or measurement systems or they may be derived from values in other protection zones. Comparison with other such readings to within required relaying accuracy verifies voltage & current sensing devices, wiring, and analog signal input processing of the relays. One

effective way to do this is to utilize the relay metered values directly in SCADA, where they can be compared with other references or state estimator values.

5. Breaker status indication from auxiliary contacts is verified in the same way as in (2). Status indications must be consistent with the flow or absence of current.
6. Continuity of the breaker trip circuit from dc bus through the trip coil is monitored by the relay and reported via communications.
7. Correct operation of the on-off carrier channel is also critical to security of the Protection System, so each carrier set has a connected or integrated automatic checkback test unit. The automatic checkback test runs several times a day. Newer carrier sets with integrated checkback testing check for received signal level and report abnormal channel attenuation or noise, even if the problem is not severe enough to completely disable the channel.

These monitoring activities plus the check-back test comprise automatic verification of all the Protection System elements that experience tells us are the most prone to fail. But, does this comprise a complete verification?

Figure A-2



The dotted boxes of Figure A-2 show the sections of verification defined by the monitoring and verification practices just listed. These sections are not completely overlapping, and the shaded regions show elements that are not verified:

1. The continuity of trip coils is verified, but no means is provided for validating the ability of the circuit breaker to trip if the trip coil should be energized.

2. Within each line relay, all the microprocessors that participate in the trip decision have been verified by internal monitoring. However, the trip circuit is actually energized by the contacts of a small telephone-type "ice cube" relay within the line protective relay. The microprocessor energizes the coil of this ice cube relay through its output data port and a transistor driver circuit. There is no monitoring of the output port, driver circuit, ice cube relay, or contacts of that relay. These components are critical for tripping the circuit breaker for a Fault.
3. The check-back test of the carrier channel does not verify the connections between the relaying microprocessor internal decision programs and the carrier transmitter keying circuit or the carrier receiver output state. These connections include microprocessor I/O ports, electronic driver circuits, wiring, and sometimes telephone-type auxiliary relays.
4. The correct states of breaker and disconnect switch auxiliary contacts are monitored, but this does not confirm that the state change indication is correct when the breaker or switch opens.

A practical solution for (1) and (2) is to observe actual breaker tripping, with a specified maximum time interval between trip tests. Clearing of naturally-occurring Faults are demonstrations of operation that reset the time interval clock for testing of each breaker tripped in this way. If Faults do not occur, manual tripping of the breaker through the relay trip output via data communications to the relay microprocessor meets the requirement for periodic testing.

PRC-005-4 does not address breaker maintenance, and its Protection System test requirements can be met by energizing the trip circuit in a test mode (breaker disconnected) through the relay microprocessor. This can be done via a front-panel button command to the relay logic, or application of a simulated Fault with a relay test set. However, utilities have found that breakers often show problems during Protection System tests. It is recommended that Protection System verification include periodic testing of the actual tripping of connected circuit breakers.

Testing of the relay-carrier set interface in (3) requires that each relay key its transmitter, and that the other relay demonstrate reception of that blocking carrier. This can be observed from relay or DFR records during naturally occurring Faults, or by a manual test. If the checkback test sequence were incorporated in the relay logic, the carrier sets and carrier channel are then included in the overlapping segments monitored by the two relays, and the monitoring gap is completely eliminated.

Appendix B

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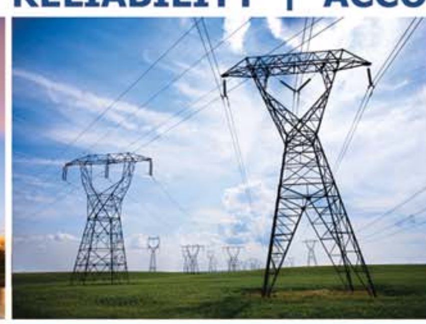
Supplementary Reference and FAQ

PRC-005-4~~X~~ Protection System Maintenance and Testing

~~July~~ October 2014

RELIABILITY | ACCOUNTABILITY



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1. Introduction and Summary

Note: This supplementary reference for PRC-005-4~~X~~ is neither mandatory nor enforceable.

NERC currently has four Reliability Standards that are mandatory and enforceable in the United States and Canada and address various aspects of maintenance and testing of Protection and Control Systems.

These standards are:

PRC-005-1b — Transmission and Generation Protection System Maintenance and Testing

PRC-008-0 — Underfrequency Load Shedding Equipment Maintenance Programs

PRC-011-0 — UVLS System Maintenance and Testing

PRC-017-0 — Special Protection System Maintenance and Testing

While these standards require that applicable entities have a maintenance program for Protection Systems, and that these entities must be able to demonstrate they are carrying out such a program, there are no specifics regarding the technical requirements for Protection System maintenance programs. Furthermore, FERC Order 693 directed additional modifications respective to Protection System maintenance programs. PRC-005-3 will replace PRC-005-2 which combined and replaced PRC-005, PRC-008, PRC-011 and PRC-017. PRC-005-3 adds Automatic Reclosing to PRC-005-2. PRC-005-2 addressed these directed modifications and replaces PRC-005, PRC-008, PRC-011 and PRC-017.

FERC Order 758 further directed that maintenance of reclosing relays and sudden pressure relays that affect the reliable operation of the Bulk Power System be addressed. PRC-005-3 addresses this directive regarding reclosing relays, and, when approved, will supersede PRC-005-2. PRC-005-4~~X~~ addresses this directive regarding sudden pressure relays and, when approved, will supersede PRC-005-3.

This document augments the Supplementary Reference and FAQ previously developed for PRC-005-2 by including discussion relevant to Automatic Reclosing added in PRC-005-3 and Sudden Pressure Relaying in PRC-005-4~~X~~.

2. Need for Verifying Protection System Performance

Protective relays have been described as silent sentinels, and do not generally demonstrate their performance until a Fault or other power system problem requires that they operate to protect power system Elements, or even the entire Bulk Electric System (BES). Lacking Faults, switching operations or system problems, the Protection Systems may not operate, beyond static operation, for extended periods. A Misoperation - a false operation of a Protection System or a failure of the Protection System to operate, as designed, when needed - can result in equipment damage, personnel hazards, and wide-area Disturbances or unnecessary customer outages. Maintenance or testing programs are used to determine the performance and availability of Protection Systems.

Typically, utilities have tested Protection Systems at fixed time intervals, unless they had some incidental evidence that a particular Protection System was not behaving as expected. Testing practices vary widely across the industry. Testing has included system functionality, calibration of measuring devices, and correctness of settings. Typically, a Protection System must be visited at its installation site and, in many cases, removed from service for this testing.

Fundamentally, a Reliability Standard for Protection System Maintenance and Testing requires the performance of the maintenance activities that are necessary to detect and correct plausible age and service related degradation of the Protection System components, such that a properly built and commissioned Protection System will continue to function as designed over its service life.

Similarly station batteries, which are an important part of the station dc supply, are not called upon to provide instantaneous dc power to the Protection System until power is required by the Protection System to operate circuit breakers or interrupting devices to clear Faults or to isolate equipment.

2.1 Existing NERC Standards for Protection System Maintenance and Testing

For critical BES protection functions, NERC standards have required that each utility or asset owner define a testing program. The starting point is the existing Standard PRC-005, briefly restated as follows:

Purpose: To document and implement programs for the maintenance of all Protection Systems affecting the reliability of the Bulk Electric System (BES) so that these Protection Systems are kept in working order.

PRC-005-4~~X~~ is not specific on where the boundaries of the Protection Systems lie. However, the definition of Protection System in the NERC Glossary of Terms used in Reliability Standards indicates what must be included as a minimum.

At the beginning of the project to develop PRC-005-2, the definition of Protection System was:

Protective relays, associated communications Systems, voltage and current sensing devices, station batteries and dc control circuitry.

Applicability: Owners of generation and transmission Protection Systems.

Requirements: The owner shall have a documented maintenance program with test intervals. The owner must keep records showing that the maintenance was performed at the specified intervals.

2.2 Protection System Definition

The most recently approved definition of Protection Systems is:

- Protective relays which respond to electrical quantities,
- Communications systems necessary for correct operation of protective functions,
- Voltage and current sensing devices providing inputs to protective relays,
- Station dc supply associated with protective functions (including station batteries, battery chargers, and non-battery-based dc supply), and
- Control circuitry associated with protective functions through the trip coil(s) of the circuit breakers or other interrupting devices.

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:

"*…that are installed for the purpose of detecting Faults on BES Elements (lines, buses, transformers, etc.).*"

The drafting team intends that this standard will follow with any definition of the Bulk Electric System. There should be no ambiguity; if the Element is a BES Element, then the Protection System protecting that Element should then be included within this standard. If there is regional variation to the definition, then there will be a corresponding regional variation to the Protection Systems that fall under this standard.

There is no way for the Standard Drafting Team to know whether a specific 230KV line, 115KV line (even 69KV line), for example, should be included or excluded. Therefore, the team set the clear intent that the standard language should simply be applicable to Protection Systems for BES Elements.

The BES is a NERC defined term that, from time to time, may undergo revisions. Additionally, there may even be regional variations that are allowed in the present and future definitions. See the NERC Glossary of Terms for the present, in-force definition. See the applicable Regional Reliability Organization for any applicable allowed variations.

While this standard will undergo revisions in the future, this standard will not attempt to keep up with revisions to the NERC definition of BES, but, rather, simply make BES Protection Systems applicable.

The Standard is applied to Generator Owners (GO) and Transmission Owners (TO) because GOs and TOs have equipment that is BES equipment. The standard brings in Distribution Providers (DP) because, depending on the station configuration of a particular substation, there may be

Protection System equipment installed at a non-transmission voltage level (Distribution Provider equipment) that is wholly or partially installed to protect the BES. PRC-005-4~~X~~ would apply to this equipment. An example is underfrequency load-shedding, which is frequently applied well down into the distribution system to meet PRC-007-0.

PRC-005-2 replaced the existing PRC-005, PRC-008, PRC-011 and PRC-017. Much of the original intent of those standards was carried forward whenever it was possible to continue the intent without a disagreement with FERC Order 693. For example, the original PRC-008 was constructed quite differently than the original PRC-005. The drafting team agrees with the intent of this and notes that distributed tripping schemes would have to exhibit multiple failures to trip before they would prove to be significant, as opposed to a single failure to trip of, for example, a transmission Protection System Bus Differential lock-out relay. While many failures of these distribution breakers could add up to be significant, it is also believed that distribution breakers are operated often on just Fault clearing duty; and, therefore, the distribution circuit breakers are operated at least as frequently as stipulated in any requirement in this standard.

Additionally, since PRC-005-2 replaced PRC-011, it will be important to make the distinction between under-voltage Protection Systems that protect individual Loads and Protection Systems that are UVLS schemes that protect the BES. Any UVLS scheme that had been applicable under PRC-011 is now applicable under PRC-005-2. An example of an under-voltage load-shedding scheme that is not applicable to this standard is one in which the tripping action was intended to prevent low distribution voltage to a specific Load from a Transmission system that was intact except for the line that was out of service, as opposed to preventing a Cascading outage or Transmission system collapse.

It had been correctly noted that the devices needed for PRC-011 are the very same types of devices needed in PRC-005.

Thus, a standard written for Protection Systems of the BES can easily make the needed requirements for Protection Systems, and replace some other standards at the same time.

2.3.1 Frequently Asked Questions:

What exactly is the BES, or Bulk Electric System?

BES is the abbreviation for Bulk Electric System. BES is a term in the Glossary of Terms used in Reliability Standards, and is not being modified within this draft standard.

~~NERC's approved definition of Bulk Electric System is:~~

~~As defined by the Regional Reliability Organization, the electrical generation resources, transmission lines, Interconnections with neighboring Systems, and associated equipment, generally operated at voltages of 100 kV or higher. Radial transmission Facilities serving only Load with one transmission source are generally not included in this definition.~~

~~The BES definition is presently undergoing the process of revision.~~

~~Each regional entity implements a definition of the Bulk Electric System that is based on this NERC definition; in some cases, supplemented by additional criteria. These regional definitions have been documented and provided to FERC as part of a *June 14, 2007 Informational Filing*.~~

Why is Distribution Provider included within the Applicable Entities and as a responsible entity within several of the requirements? Wouldn't anyone having relevant Facilities be a Transmission Owner?

Depending on the station configuration of a particular substation, there may be Protection System equipment installed at a non-transmission voltage level (Distribution Provider equipment) that is wholly or partially installed to protect the BES. PRC-005-4~~X~~ applies to this equipment. An example is underfrequency load-shedding, which is frequently applied well down into the distribution system to meet PRC-007-0.

We have an under voltage load-shedding (UVLS) system in place that prevents one of our distribution substations from supplying extremely low voltage in the case of a specific transmission line outage. The transmission line is part of the BES. Does this mean that our UVLS system falls within this standard?

The situation, as stated, indicates that the tripping action was intended to prevent low distribution voltage to a specific Load from a Transmission System that was intact, except for the line that was out of service, as opposed to preventing Cascading outage or Transmission System Collapse.

This standard is not applicable to this UVLS.

We have a UFLS or UVLS scheme that sheds the necessary Load through distribution-side circuit breakers and circuit reclosers. Do the trip-test requirements for circuit breakers apply to our situation?

No. Distributed tripping schemes would have to exhibit multiple failures to trip before they would prove to be significant, as opposed to a single failure to trip of, for example, a transmission Protection System bus differential lock-out relay. While many failures of these distribution breakers could add up to be significant, it is also believed that distribution breakers are operated often on just Fault clearing duty; and, therefore, the distribution circuit breakers are operated at least as frequently as any requirements that might have appeared in this standard.

We have a UFLS scheme that, in some locales, sheds the necessary Load through non-BES circuit breakers and, occasionally, even circuit switchers. Do the trip-test requirements for circuit breakers apply to our situation?

If your "non-BES circuit breaker" has been brought into this standard by the inclusion of UFLS requirements, and otherwise would not have been brought into this standard, then the answer is that there are no trip-test requirements. For these devices that are otherwise non-BES assets, these tripping schemes would have to exhibit multiple failures to trip before they would prove to be as significant as, for example, a single failure to trip of a transmission Protection System bus differential lock-out relay.

How does the "Facilities" section of "Applicability" track with the standards that will be retired once PRC-005-2 becomes effective?

In establishing PRC-005-2, the drafting team combined legacy standards PRC-005-1b, PRC-008-0, PRC-011-0, and PRC-017-0. The merger of the subject matter of these standards is reflected in Applicability 4.2.

The intent of the drafting team is that the legacy standards be reflected in PRC-005-2 as follows:

- Applicability of PRC-005-1b for Protection Systems relating to non-generator elements of the BES is addressed in 4.2.1;
- Applicability of PRC-008-0 for underfrequency load shedding systems is addressed in 4.2.2;
- Applicability of PRC-011-0 for undervoltage load shedding relays is addressed in 4.2.3;
- Applicability of PRC-017-0 for ~~Special Protection Systems~~Remedial Action Systems is addressed in 4.2.4;
- Applicability of PRC-005-1b for Protection Systems for BES generators is addressed in 4.2.5.

2.4 Applicable Relays

The NERC Glossary definition has a Protection System including relays, dc supply, current and voltage sensing devices, dc control circuitry and associated communications circuits. The relays to which this standard applies are those protective relays that respond to electrical quantities and provide a trip output to trip coils, dc control circuitry or associated communications equipment. This definition extends to IEEE Device No. 86 (lockout relay) and IEEE Device No. 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.

Relays that respond to non-electrical inputs or impulses (such as, but not limited to, vibration, seismic, thermal or gas accumulation) are not included.

Automatic Reclosing is addressed in PRC-005-3 by explicitly addressing them outside the definition of Protection System. The specific locations for applicable Automatic Reclosing are addressed in Applicability Section 4.2.6.

Sudden Pressure Relaying is addressed in PRC-005-4~~X~~ by explicitly addressing them outside the definition of Protection System. The specific locations for applicable Sudden Pressure Relaying are addressed in Applicability Section 4.2.1, 4.2.5.2, 4.2.5.3 and 4.2.5.4.

2.4.1 Frequently Asked Questions:

Are power circuit reclosers, reclosing relays, closing circuits and auto-restoration schemes covered in this Standard?

Yes. Automatic Reclosing includes reclosing relays and the associated dc control circuitry. Section 4.2.6 of the Applicability specifically limits the applicable reclosing relays to:

4.2.6 Automatic Reclosing

4.2.6.1 Automatic Reclosing applied on the terminals of Elements connected to the BES bus located at generating plant substations where the total installed gross generating plant capacity is greater than the gross capacity of the largest BES generating unit within the Balancing Authority Area or, if a member of a Reserve Sharing Group, the largest generating unit within the Reserve Sharing Group.

4.2.6.2 Automatic Reclosing applied on the terminals of all BES Elements at substations one bus away from generating plants specified in Section 4.2.6.1 when the substation is less than 10 circuit-miles from the generating plant substation.

4.2.6.3 Automatic Reclosing applied as an integral part of a ~~SPS~~ RAS specified in Section 4.2.4.

Further, Footnote 1 to Applicability Section 4.2.6 establishes that Automatic Reclosing addressed in 4.2.6.1 and 4.2.6.2 may be excluded if the equipment owner can demonstrate that a close-in three-phase fault present for twice the normal clearing time (capturing a minimum trip-close-trip time delay) does not result in a total loss of gross generation in the Interconnection exceeding the gross capacity of the largest relevant BES generating unit where the Automatic Reclosing is applied.

Additionally, Footnote 2 to Applicability Section 4.2.6.1 advises that the entity's PSMP needs to remain current regarding the applicability of Automatic Reclosing Components relative to the largest generating unit within the Balancing Authority Area or Reserve Sharing Group.

The Applicability as detailed above was recommended by the NERC System Analysis and Modeling Subcommittee (SAMS) after a lengthy review of the use of reclosing within the BES. SAMS concluded that automatic reclosing is largely implemented throughout the BES as an operating convenience, and that automatic reclosing mal-performance affects BES reliability only when the reclosing is part of a ~~Special Protection System~~Remedial Action System, or when premature autoreclosing has the potential to cause generating unit or plant instability. A technical report, "Considerations for Maintenance and Testing of Autoreclosing Schemes — November 2012", is referenced in PRC-005-3 and provides a more detailed discussion of these concerns.

Why did the standard drafting team not include IEEE device numbers to describe Automatic Reclosing Relays?

The drafting team elected not to include IEEE device numbers to describe Automatic Reclosing because Automatic Reclosing component type could be a stand-alone electromechanical relay; or could be the 79 function within a microprocessor based multi-function relay(11).

Is a sync-check (25) relay included in the Automatic Reclosing Control Circuitry?

Where sync-check relays are included in an Automatic Reclosing scheme that is part of an ~~SPS,~~RAS, the sync-check would be included in the control circuitry (Table 4-2(b)). Where sync-check relays are included in an Automatic Reclosing scheme that is not part of an ~~SPS,~~RAS, the sync-check would not be included in the control circuitry (Table 4-2(a)).

The SDT asserts that a sync-check (25) relay does not initiate closing but rather enables or disables closing and is not considered a part of the actual Automatic Reclosing control circuitry when not part of an ~~SPS.~~RAS.

How do I interpret Applicability Section 4.2.6 to determine applicability in the following examples:

At my generating plant substation, I have a total of 800 MW connected to one voltage level and 200 MW connected to another voltage level. How do I determine my gross capacity? Where do I consider Automatic Reclosing to be applicable?

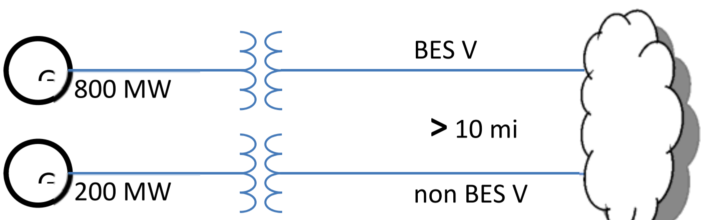
Scenario number 1:

The 800 MW of generation is connected to a BES voltage level bus, the 200 MW

is connected to a non-BES voltage level bus, and there is no connection between the two buses locally or within 10 circuit miles from the generating plant substation. The largest single unit in the BA area is 750 MW.

In this case, the total installed gross generating capacity would be 800 MW. The two units are essentially independent plants.

The BES voltage level bus is considered to be the bus to which the 800 MW of generation is connected. Any BES Automatic Reclosing at this location, as well as other locations within 10 circuit miles, is considered to be applicable because 800 MW exceeds the largest single unit in the BA area.



[Essentially independent plants]

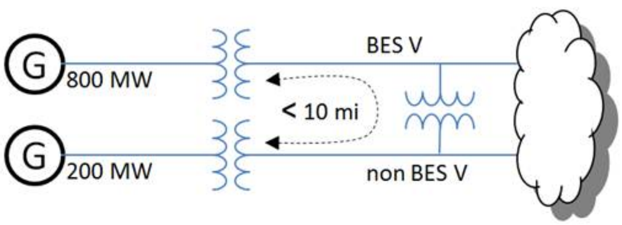
Gross Capacity	**Automatic Reclosing in scope**
800 MW	BES V

Scenario number 2:

The 800 MW of generation is connected to a BES voltage level bus, the 200 MW unit is connected to a non-BES voltage level bus, and there is a connection between the two buses locally or within 10 circuit miles from the generating plant substation. The largest single unit in the BA area is 750 MW.

In this case, reclosing into a fault on the BES system could impact the stability of the non-BES-connected generating units. Therefore, the total installed gross generating capacity would be 1000 MW.

The BES voltage level bus is considered to be the bus to which the 800 MW of generation is connected. Any BES Automatic Reclosing at this location, as well as other locations within 10 circuit miles, is considered to be applicable because total of 1000 MW exceeds the largest single unit in the BA area. However, the Automatic Reclosing on the non-BES voltage level bus is not applicable.



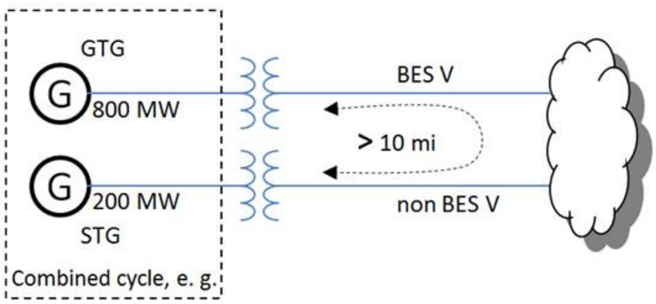
Gross Capacity	Automatic Reclosing in scope
1000 MW	BES V

Scenario number 3:

The 800 MW of generation is connected to a BES voltage level bus, the 200 MW unit is connected to a non-BES voltage level bus, and there is no connection between the two buses locally or within 10 circuit miles from the generating plant substation but the generating units connected at the BES voltage level do not operate independently of the units connected at the non BES voltage level (e.g., a combined cycle facility where 800 MW of combustion turbines are connected at a BES voltage level whose exhaust is used to power a 200 MW steam unit connected to a non BES voltage level. The largest single unit in the BA area is 750 MW.

In this case, the total installed gross generating capacity would be 1000 MW. Therefore, reclosing into a fault on the BES voltage level would result in a loss of the 800 MW combustion turbines and subsequently result in the loss of the 200 MW steam unit because of the loss of the heat source to its boiler.

The BES voltage level bus is considered to be the bus to which the 800 MW of generation is connected. Any BES Automatic Reclosing at this location, as well as other locations within 10 circuit miles, is considered to be applicable because total of 1000 MW exceeds the largest single unit in the BA area. However, the Automatic Reclosing on the non-BES voltage level bus is not applicable.



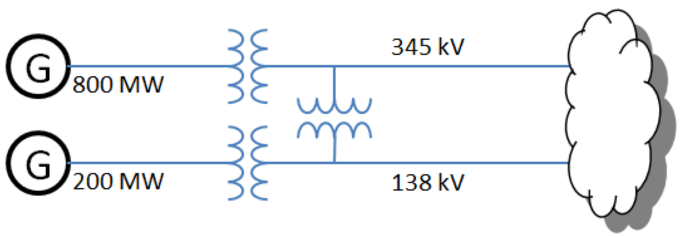
Gross Capacity	**Automatic Reclosing in scope**
1000 MW	BES V

Scenario 4

The 800 MW of generation is connected at 345 kV and the 200 MW is connected at 138 kV with an autotransformer at the generating plant substation connecting the two voltage levels. The largest single unit in the BA area is 900 MW.

In this case, the total installed gross generating capacity would be 1000 MW and section 4.2.6.1 would be applicable to both the 345 kV Automatic Reclosing Components and the 138 kV Automatic Reclosing Components, since the total capacity of 1000 MW is larger than the largest single unit in the BA area.

However, if the 345 kV and the 138 kV systems can be shown to be uncoupled such that the 138 kV reclosing relays will not affect the stability of the 345 kV generating units then the 138 kV Automatic Reclosing Components need not be included per section 4.2.6.1.



Gross Capacity	Automatic Reclosing in scope
1000 MW	BOTH*

* The study detailed in Footnote 1 of the draft standard may eliminate the 138 kV Automatic Reclosing Components and/or the 345 kV Automatic Reclosing Components

Why does 4.2.6.2 specify "10 circuit miles"?

As noted in "Considerations for Maintenance and Testing of Autoreclosing Schemes — November 2012", transmission line impedance on the order of one mile away typically provides adequate impedance to prevent generating unit instability and a 10 mile threshold provides sufficient margin.

Should I use MVA or MW when determining the installed gross generating plant capacity?

Be consistent with the rating used by the Balancing Authority for the largest BES generating unit within their area.

What value should we use for generating plant capacity in 4.2.6.1?

Use the value reported to the Balance Authority for generating plant capacity for planning and modeling purposes. This can be nameplate or other values based on generating plant limitations such as boiler or turbine ratings.

What is considered to be "one bus away" from the generation?

The BES voltage level bus is considered to be the generating plant substation bus to which the generator step-up transformer is connected. "One bus away" is the next bus, connected by either a transmission line or transformer.

I use my protective relays only as sources of metered quantities and breaker status for SCADA and EMS through a substation distributed RTU or data concentrator to the control center. What are the maintenance requirements for the relays?

This standard addresses Protection Systems that are installed for the purpose of detecting Faults on BES Elements (lines, buses, transformers, etc.). Protective relays, providing only the functions mentioned in the question, are not included.

Are Reverse Power Relays installed on the low-voltage side of distribution banks considered to be components of "Protection Systems that are installed for the purpose of detecting Faults on BES Elements (lines, buses, transformers, etc.)"?

Reverse power relays are often installed to detect situations where the transmission source becomes de-energized and the distribution bank remains energized from a source on the low-voltage side of the transformer and the settings are calculated based on the charging current of the transformer from the low-voltage side. Although these relays may operate as a result of a fault on a BES element, they are not 'installed for the purpose of detecting' these faults.

Why is the maintenance of Sudden Pressure Relaying being addressed in PRC-005-4~~X~~?

Proper performance of Sudden Pressure Relaying supports the reliability of the BES because fault pressure relays can detect rapid changes in gas pressure, oil pressure, or oil flow that are indicative of faults within liquid-filled, wire-wound equipment such as turn-to-turn faults which may be undetected by Protection Systems. Additionally, Sudden Pressure

Relaying can quickly detect faults and operate to limit damage to liquid-filled, wire-wound equipment.

What type of devices are classified as fault pressure relay?

There are three main types of fault pressure relays; rapid gas pressure rise, rapid oil pressure rise, and rapid oil flow devices.

Rapid gas pressure devices monitor the pressure in the space above the oil (or other liquid), and initiate tripping action for a rapid rise in gas pressure resulting from the rapid expansion of the liquid caused by a fault. The sensor is located in the gas space.

Rapid oil pressure devices monitor the pressure in the oil (or other liquid), and initiate tripping action for a rapid pressure rise caused by a fault. The sensor is located in the liquid.

Rapid oil flow devices ("Buchholz") monitor the liquid flow between a transformer/reactor and its conservator. Normal liquid flow occurs continuously with ambient temperature changes and with internal heating from loading and does not operate the rapid oil flow device. However, when an internal arc happens a sudden expansion of liquid can be monitored as rapid liquid flow from the transformer into the conservator resulting in actuation of the rapid oil flow device.

Are sudden pressure relays that only initiate an alarm included in the scope of PRC-005-4~~X~~?

No, the definition of Sudden Pressure Relaying specifies only those that trip an interrupting device(s) to isolate the equipment it is monitoring.

Are pressure relief devices included in the scope of PRC-005-4~~X~~?

No. PRDs are not included in the Sudden Pressure Relaying definition.

Is Sudden Pressure Relaying installed on distribution transformers included in PRC-005-4~~X~~?

No, Applicability 4.2.1, 4.2.5.2, 4.2.5.3, 4.2.5.4, explicitly describe what Sudden Pressure Relaying is included within the standard.

Are non-electrical sensing devices (other than fault pressure relays) such as low oil level or high winding temperatures included in PRC-005-4~~X~~?

No, based on the SPCS technical document, "Sudden Pressure Relays and Other Devices that Respond to Non-Electrical Quantities – December 2013," the only applicable non-electrical sensing devices are Sudden Pressure Relays.

~~How do I verify the pressure or flow sensing mechanism is operable?~~

~~Maintenance activities for the fault pressure relay associated with Sudden Pressure Relaying in PRC-005-X are intended to verify that the pressure and/or flow sensing mechanism are functioning correctly. Beyond this, PRC-005-X requires no calibration (adjusting the operating threshold or measurement accuracy of a measuring element to meet the intended performance requirement) or testing (applying signals to a component to observe functional performance or output behavior, or to diagnose problems) activities. For example, some designs of flow~~

~~sensing mechanisms allow the operation of a test switch to actuate the limit switch of the flow sensing mechanism. Operation of this test switch and verification of the flow sensing mechanism would meet the requirements of the maintenance activity. Another example involves a gas pressure sensing mechanism which is isolated by a test plug. Removal of the plug and verification of the bellows mechanism would meet the requirements of the maintenance activity.~~

~~*Why the 6-year maximum maintenance interval for fault pressure relays?*~~

~~The SDT established the six-year maintenance interval for fault pressure relays (see Table 5, PRC-005-X) based on the recommendation of the System Protection and Control Subcommittee (SPCS). The technical experts of the SPCS were tasked with developing the technical documents to:~~

~~i. Describe the devices and functions (to include sudden pressure relays which trip for fault conditions) that should address FERC's concern; and~~

~~ii. Propose minimum maintenance activities for such devices and maximum maintenance intervals, including the technical basis for each.~~

~~Excerpt from the SPCS technical report: "In order to determine present industry practices related to sudden pressure relay maintenance, the SPCS conducted a survey of Transmission Owners and Generator Owners in all eight Regions requesting information related to their maintenance practices. The SPCS received responses from 75 Transmission Owners and 109 Generator Owners. Note that, for the purpose of the survey, sudden pressure relays included the following: the "sudden pressure relay" (SPR) originally manufactured by Westinghouse, the "rapid pressure rise relay" (RPR) manufactured by Qualitrol, and a variety of Buchholz relays.~~

~~Table 2 provides a summary of the results of the responses:~~

~~Table 2: Sudden Pressure Relay Maintenance Practices – Survey Results~~		
~~-~~	~~**Transmission Owner**~~	~~**Generator Owner**~~
~~Number of responding owners that trip with Sudden Pressure Relays:~~	~~67~~	~~84~~
~~Percentage of responding owners who trip that have a Maintenance Program:~~	~~75%~~	~~78%~~
~~Percentage of maintenance programs that include testing the pressure actuator:~~	~~81%~~	~~77%~~
~~Average Maintenance interval reported:~~	~~5.9 years~~	~~4.9 years~~

~~Additionally, in order to validate the information noted above, the SPCS contacted the following entities for their feedback: the IEEE Power System Relaying Committee, the IEEE Transformer Committee, the Doble Transformer Committee, the NATF System Protection Practices Group, and the EPRI Generator Owner/Operator Technical Focus Group. All of these organizations indicated the results of the SPCS survey are consistent with their respective experiences.~~

~~The SPCS discussed the potential difference between the recommended intervals for fault pressure relaying and intervals for transformer maintenance. The SPCS developed the recommended intervals for fault pressure relaying by comparing fault pressure relaying to Protection System Components with similar physical attributes. The SPCS recognized that these intervals may be shorter than some existing or future transformer maintenance intervals, but believed it to be more important to base intervals for fault pressure relaying on similar Protection System Components than transformer maintenance intervals.~~

~~The maintenance interval for fault pressure relays can be extended by utilizing performance-based maintenance thereby allowing entities that have maintenance intervals for transformers in excess of six years, to align them.~~

The standard specifically mentions auxiliary and lock-out relays. What is an auxiliary tripping relay?

An auxiliary relay, IEEE Device No. 94, is described in IEEE Standard C37.2-2008 as: "A device that functions to trip a circuit breaker, contactor, or equipment; to permit immediate tripping by other devices; or to prevent immediate reclosing of a circuit interrupter if it should open automatically, even though its closing circuit is maintained closed."

What is a lock-out relay?

A lock-out relay, IEEE Device No. 86, is described in IEEE Standard C37.2 as: "A device that trips and maintains the associated equipment or devices inoperative until it is reset by an operator, either locally or remotely."

3. Protection System and Automatic Reclosing Product Generations

The likelihood of failure and the ability to observe the operational state of a critical Protection System and Automatic Reclosing both depend on the technological generation of the relays, as well as how long they have been in service. Unlike many other transmission asset groups, protection and control systems have seen dramatic technological changes spanning several generations. During the past 20 years, major functional advances are primarily due to the introduction of microprocessor technology for power system devices, such as primary measuring relays, monitoring devices, control Systems, and telecommunications equipment.

Modern microprocessor-based relays have six significant traits that impact a maintenance strategy:

- Self-monitoring capability - the processors can check themselves, peripheral circuits, and some connected substation inputs and outputs, such as trip coil continuity. Most relay users are aware that these relays have self-monitoring, but are not focusing on exactly what internal functions are actually being monitored. As explained further below, every element critical to the Protection System must be monitored, or else verified periodically.
- Ability to capture Fault records showing how the Protection System responded to a Fault in its zone of protection, or to a nearby Fault for which it is required not to operate.
- Ability to meter currents and voltages, as well as status of connected circuit breakers, continuously during non-Fault times. The relays can compute values, such as MW and MVAR line flows, that are sometimes used for operational purposes, such as SCADA.
- Data communications via ports that provide remote access to all of the results of Protection System monitoring, recording and measurement.
- Ability to trip or close circuit breakers and switches through the Protection System outputs, on command from remote data communications messages, or from relay front panel button requests.
- Construction from electronic components, some of which have shorter technical life or service life than electromechanical components of prior Protection System generations.

There have been significant advances in the technology behind the other components of Protection Systems. Microprocessors are now a part of battery chargers, associated communications equipment, voltage and current-measuring devices, and even the control circuitry (in the form of software-latches replacing lock-out relays, etc.).

Any Protection System component can have self-monitoring and alarming capability, not just relays. Because of this technology, extended time intervals can find their way into all components of the Protection System.

This standard also recognizes the distinct advantage of using advanced technology to justifiably defer or even eliminate traditional maintenance. Just as a hand-held calculator does not require routine testing and calibration, neither does a calculation buried in a microprocessor-based device that results in a "lock-out." Thus, the software-latch 86 that replaces an electro-mechanical 86 does not require routine trip testing. Any trip circuitry associated with the "soft 86" would still need applicable verification activities performed, but the actual "86" does not have to be "electrically operated" or even toggled.

4. Definitions

Protection System Maintenance Program (PSMP) — An ongoing program by which Protection System, Automatic Reclosing and Sudden Pressure Relaying Components are kept in working order and proper operation of malfunctioning Components is restored. A maintenance program for a specific Component includes one or more of the following activities:

- Verify — Determine that the Component is functioning correctly.
- Monitor — Observe the routine in-service operation of the Component.
- Test — Apply signals to a Component to observe functional performance or output behavior, or to diagnose problems.
- Inspect — Detect visible signs of Component failure, reduced performance and degradation.
- Calibrate — Adjust the operating threshold or measurement accuracy of a measuring element to meet the intended performance requirement.

Automatic Reclosing – Includes the following Components:

- Reclosing relay
- Control circuitry associated with the reclosing relay.

Sudden Pressure Relaying – A system that trips an interrupting device(s) to isolate the equipment it is monitoring and includes the following Components:

- Fault pressure relay – a mechanical relay or device that detects rapid changes in gas pressure, oil pressure, or oil flow that are indicative of faults within liquid-filled, wire-wound equipment
- Control circuitry associated with a fault pressure relay

Unresolved Maintenance Issue – A deficiency identified during a maintenance activity that causes the component to not meet the intended performance, cannot be corrected during the maintenance interval, and requires follow-up corrective action.

Segment – Components of a consistent design standard, or a particular model or type from a single manufacturer that typically share other common elements. Consistent performance is expected across the entire population of a Segment. A Segment must contain at least sixty (60) individual Components.

Component Type –

- Any one of the five specific elements of a Protection System.
- Any one of the two specific elements of Automatic Reclosing.
- Any one of the two specific elements of Sudden Pressure Relaying.

Component – Any individual discrete piece of equipment included in a Protection System, Automatic Reclosing, or Sudden Pressure Relaying.

Countable Event – A failure of a Component requiring repair or replacement, any condition discovered during the maintenance activities in Tables 1-1 through 1-5, Table 3, Tables 4-1 through 4-2, and Table 5, which requires corrective action or a Protection System Misoperation attributed to hardware failure or calibration failure. Misoperations due to product design errors, software errors, relay settings different from specified settings, Protection System Component, Automatic Reclosing or Sudden Pressure Relaying configuration or application errors are not included in Countable Events.

4.1 Frequently Asked Questions:

Why does PRC-005-4~~X~~ not specifically require maintenance and testing procedures, as reflected in the previous standard, PRC-005-1?

PRC-005-1 does not require detailed maintenance and testing procedures, but instead requires summaries of such procedures, and is not clear on what is actually required. PRC-005-4~~X~~ requires a documented maintenance program, and is focused on establishing requirements rather than prescribing methodology to meet those requirements. Between the activities identified in the Tables 1-1 through 1-5, Table 2, Table 3, and Table 4 (collectively the "Tables"), and the various components of the definition established for a "Protection System Maintenance Program," PRC-005-4~~X~~ establishes the activities and time basis for a Protection System Maintenance Program to a level of detail not previously required.

Please clarify what is meant by "restore" in the definition of maintenance.

The description of "restore" in the definition of a Protection System Maintenance Program addresses corrective activities necessary to assure that the component is returned to working order following the discovery of its failure or malfunction. The Maintenance Activities specified in the Tables do not present any requirements related to Restoration; R5 of the standard does require that the entity "shall demonstrate efforts to correct any identified Unresolved Maintenance Issues." Some examples of restoration (or correction of Unresolved Maintenance Issues) include, but are not limited to, replacement of capacitors in distance relays to bring them to working order; replacement of relays, or other Protection System components, to bring the Protection System to working order; upgrade of electromechanical or solid-state protective relays to microprocessor-based relays following the discovery of failed components. Restoration, as used in this context, is not to be confused with restoration rules as used in system operations. Maintenance activity necessarily includes both the detection of problems and the repairs needed to eliminate those problems. This standard does not identify all of the Protection System problems that must be detected and eliminated, rather it is the intent of this standard that an entity determines the necessary working order for their various devices, and keeps them in working order. If an equipment item is repaired or replaced, then the entity can restart the maintenance-time-interval-clock, if desired; however, the replacement of equipment does not remove any documentation requirements that would have been required to verify compliance with time-interval requirements. In other words, do not discard maintenance data that goes to verify your work.

The retention of documentation for new and/or replaced equipment is all about proving that the maintenance intervals had been in compliance. For example, a long-range plan of upgrades might lead an entity to ignore required maintenance; retaining the evidence of prior maintenance that existed before any retirements and upgrades proves compliance with the standard.

Please clarify what is meant by "...demonstrate efforts to correct an Unresolved Maintenance Issue..."; why not measure the completion of the corrective action?

Management of completion of the identified Unresolved Maintenance Issue is a complex topic that falls outside of the scope of this standard. There can be any number of supply, process and management problems that make setting repair deadlines impossible. The SDT specifically chose the phrase "demonstrate efforts to correct" (with guidance from NERC Staff) because of the concern that many more complex Unresolved Maintenance Issues might require greater than the remaining maintenance interval to resolve (and yet still be a "closed-end process"). For example, a problem might be identified on a VRLA battery during a six-month check. In instances such as one that requiring battery replacement as part of the long-term resolution, it is highly unlikely that the battery could be replaced in time to meet the six-calendar-month requirement for this maintenance activity. The SDT does not believe entities should be found in violation of a maintenance program requirement because of the inability to complete a remediation program within the original maintenance interval. The SDT does believe corrective actions should be timely, but concludes it would be impossible to postulate all possible remediation projects; and, therefore, impossible to specify bounding time frames for resolution of all possible Unresolved Maintenance Issues, or what documentation might be sufficient to provide proof that effective corrective action is being undertaken.

5. Time-Based Maintenance (TBM) Programs

Time-based maintenance is the process in which Protection System, Automatic Reclosing and Sudden Pressure Relaying Components are maintained or verified according to a time schedule. The scheduled program often calls for technicians to travel to the physical site and perform a functional test on Protection System components. However, some components of a TBM program may be conducted from a remote location - for example, tripping a circuit breaker by communicating a trip command to a microprocessor relay to determine if the entire Protection System tripping chain is able to operate the breaker. Similarly, all Protection System, and Sudden Pressure Relaying Components can have the ability to remotely conduct tests, either on-command or routinely; the running of these tests can extend the time interval between hands-on maintenance activities.

5.1 Maintenance Practices

Maintenance and testing programs often incorporate the following types of maintenance practices:

- TBM – time-based maintenance – externally prescribed maximum maintenance or testing intervals are applied for components or groups of components. The intervals may have been developed from prior experience or manufacturers' recommendations. The TBM verification interval is based on a variety of factors, including experience of the particular asset owner, collective experiences of several asset owners who are members of a country or regional council, etc. The maintenance intervals are fixed and may range in number of months or in years.

  TBM can include review of recent power system events near the particular terminal. Operating records may verify that some portion of the Protection System has operated correctly since the last test occurred. If specific protection scheme components have demonstrated correct performance within specifications, the maintenance test time clock can be reset for those components.

- PBM – Performance-Based Maintenance - intervals are established based on analytical or historical results of TBM failure rates on a statistically significant population of similar components. Some level of TBM is generally followed. Statistical analyses accompanied by adjustments to maintenance intervals are used to justify continued use of PBM-developed extended intervals when test failures or in-service failures occur infrequently.

- CBM – condition-based maintenance – continuously or frequently reported results from non-disruptive self-monitoring of components demonstrate operational status as those components remain in service. Whatever is verified by CBM does not require manual testing, but taking advantage of this requires precise technical focus on exactly what parts are included as part of the self-diagnostics. While the term "Condition-Based-Maintenance" (CBM) is no longer used within the standard itself, it is important to note that the concepts of CBM are a part of the standard (in the form of extended time intervals through status-monitoring). These extended time intervals are only allowed (in the absence of PBM) if the condition of the device is monitored (CBM). As a consequence of the "monitored-basis-time-intervals" existing within the standard, the explanatory discussions within this Supplementary Reference concerned with CBM will remain in this reference and are discussed as CBM.

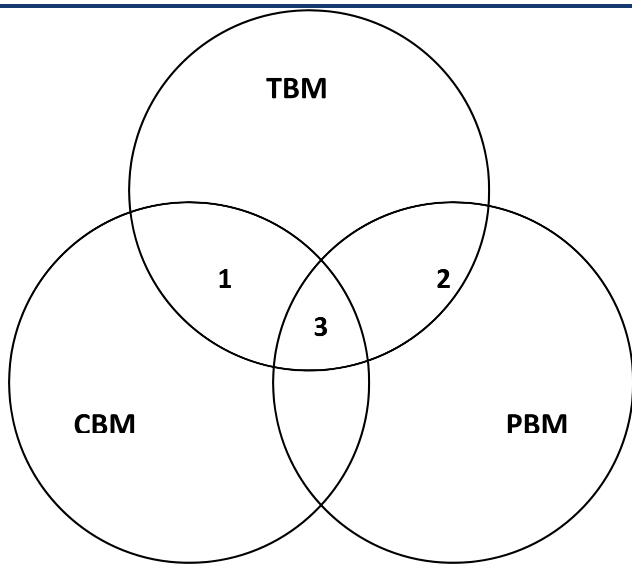
Microprocessor-based Protection System or Automatic Reclosing Components that perform continuous self-monitoring verify correct operation of most components within the device. Self-monitoring capabilities may include battery continuity, float voltages, unintentional grounds, the ac signal inputs to a relay, analog measuring circuits, processors and memory for measurement, protection, and data communications, trip circuit monitoring, and protection or data communications signals (and many, many more measurements). For those conditions, failure of a self-monitoring routine generates an alarm and may inhibit operation to avoid false trips. When internal components, such as critical output relay contacts, are not equipped with self-monitoring, they can be manually tested. The method of testing may be local or remote, or through inherent performance of the scheme during a system event.

The TBM is the overarching maintenance process of which the other types are subsets. Unlike TBM, PBM intervals are adjusted based on good or bad experiences. The CBM verification intervals can be hours, or even milliseconds between non-disruptive self-monitoring checks within or around components as they remain in service.

TBM, PBM, and CBM can be combined for individual components, or within a complete Protection System. The following diagram illustrates the relationship between various types of maintenance practices described in this section. In the Venn diagram, the overlapping regions show the relationship of TBM with PBM historical information and the inherent continuous monitoring offered through CBM.

This figure shows:

- Region 1: The TBM intervals that are increased based on known reported operational condition of individual components that are monitoring themselves.
- Region 2: The TBM intervals that are adjusted up or down based on results of analysis of maintenance history of statistically significant population of similar products that have been subject to TBM.
- Region 3: Optimal TBM intervals based on regions 1 and 2.



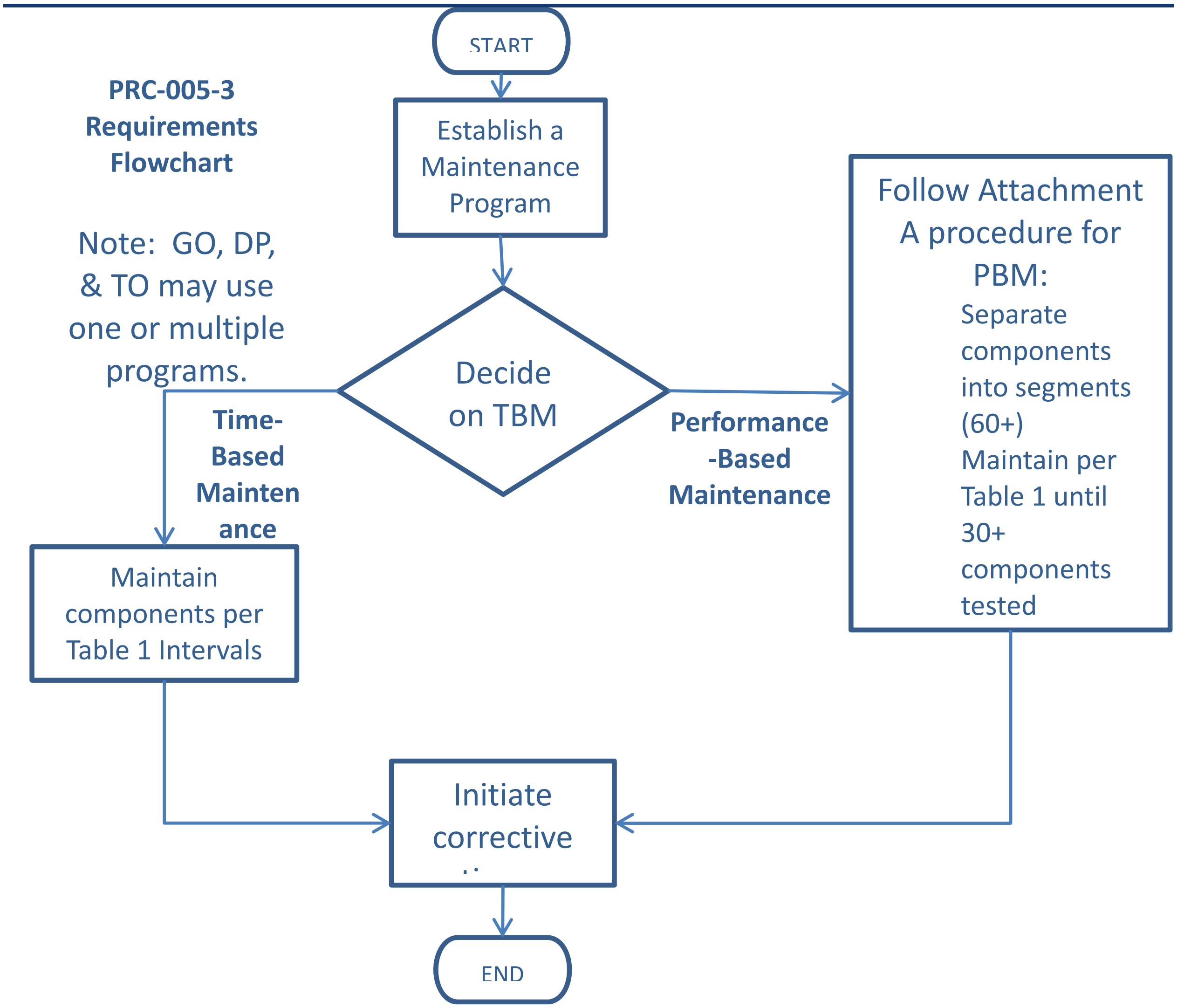
Relationship of time-based maintenance types

5.1.1 Frequently Asked Questions:

The standard seems very complicated, and is difficult to understand. Can it be simplified?

Because the standard is establishing parameters for condition-based Maintenance (R1) and Performance-Based Maintenance (R2), in addition to simple time-based Maintenance, it does appear to be complicated. At its simplest, an entity needs to ONLY perform time-based maintenance according to the unmonitored rows of the Tables. If an entity then wishes to take advantage of monitoring on its Protection System components and its available lengthened time intervals, then it may, as long as the component has the listed monitoring attributes. If an entity wishes to use historical performance of its Protection System components to perform Performance-Based Maintenance, then R2 applies.

Please see the following diagram, which provides a "flow chart" of the standard.



We have an electromechanical (unmonitored) relay that has a trip output to a lockout relay (unmonitored) which trips our transformer off-line by tripping the transformer's high-side and low-side circuit breakers. What testing must be done for this system?

This system is made up of components that are all unmonitored. Assuming a time-based Protection System Maintenance Program schedule (as opposed to a Performance-Based maintenance program), each component must be maintained per the most frequent hands-on activities listed in the Tables.

5.2 Extending Time-Based Maintenance

All maintenance is fundamentally time-based. Default time-based intervals are commonly established to assure proper functioning of each component of the Protection System, when data on the reliability of the components is not available other than observations from time-based maintenance. The following factors may influence the established default intervals:

- If continuous indication of the functional condition of a component is available (from relays or chargers or any self-monitoring device), then the intervals may be extended, or manual testing may be eliminated. This is referred to as condition-based maintenance or CBM. CBM is valid only for precisely the components subject to monitoring. In the case of microprocessor-based relays, self-monitoring may not include automated diagnostics of every component within a microprocessor.

- Previous maintenance history for a group of components of a common type may indicate that the maintenance intervals can be extended, while still achieving the desired level of performance. This is referred to as Performance-Based Maintenance, or PBM. It is also sometimes referred to as reliability-centered maintenance, or RCM; but PBM is used in this document.
- Observed proper operation of a component may be regarded as a maintenance verification of the respective component or element in a microprocessor-based device. For such an observation, the maintenance interval may be reset only to the degree that can be verified by data available on the operation. For example, the trip of an electromechanical relay for a Fault verifies the trip contact and trip path, but only through the relays in series that actually operated; one operation of this relay cannot verify correct calibration.

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. The improper application of test signals may cause failure of a component. For example, in electromechanical overcurrent relays, test currents have been known to destroy convolution springs.

In addition, maintenance usually takes the component out of service, during which time it is not able to perform its function. Cutout switch failures, or failure to restore switch position, commonly lead to protection failures.

5.2.1 Frequently Asked Questions:

If I show the protective device out of service while it is being repaired, then can I add it back as a new protective device when it returns? If not, my relay testing history would show that I was out of compliance for the last maintenance cycle.

The maintenance and testing requirements (R5) (in essence) state "…shall demonstrate efforts to correct any identified Unresolved Maintenance Issues." The type of corrective activity is not stated; however it could include repairs or replacements.

Your documentation requirements will increase, of course, to demonstrate that your device tested bad and had corrective actions initiated. Your regional entity could very well ask for documentation showing status of your corrective actions.

6. Condition-Based Maintenance (CBM) Programs

Condition-based maintenance is the process of gathering and monitoring the information available from modern microprocessor-based relays and other intelligent electronic devices (IEDs) that monitor Protection System or Automatic Reclosing elements. These devices generate monitoring information during normal operation, and the information can be assessed at a convenient location remote from the substation. The information from these relays and IEDs is divided into two basic types:

1. Information can come from background self-monitoring processes, programmed by the manufacturer, or by the user in device logic settings. The results are presented by alarm contacts or points, front panel indications, and by data communications messages.
2. Information can come from event logs, captured files, and/or oscillographic records for Faults and Disturbances, metered values, and binary input status reports. Some of these are available on the device front panel display, but may be available via data communications ports. Large files of Fault information can only be retrieved via data communications. These results comprise a mass of data that must be further analyzed for evidence of the operational condition of the Protection System.

Using these two types of information, the user can develop an effective maintenance program carried out mostly from a central location remote from the substation. This approach offers the following advantages:

Non-invasive Maintenance: The system is kept in its normal operating state, without human intervention for checking. This reduces risk of damage, or risk of leaving the system in an inoperable state after a manual test. Experience has shown that keeping human hands away from equipment known to be working correctly enhances reliability.

Virtually Continuous Monitoring: CBM will report many hardware failure problems for repair within seconds or minutes of when they happen. This reduces the percentage of problems that are discovered through incorrect relaying performance. By contrast, a hardware failure discovered by TBM may have been there for much of the time interval between tests, and there is a good chance that some devices will show health problems by incorrect operation before being caught in the next test round. The frequent or continuous nature of CBM makes the effective verification interval far shorter than any required TBM maximum interval. To use the extended time intervals available through Condition Based Maintenance, simply look for the rows in the Tables that refer to monitored items.

6.1 Frequently Asked Questions:

My microprocessor relays and dc circuit alarms are contained on relay panels in a 24-hour attended control room. Does this qualify as an extended time interval condition-based (monitored) system?

Yes, provided the station attendant (plant operator, etc.) monitors the alarms and other indications (comparable to the monitoring attributes) and reports them within the given time limits that are stated in the criteria of the Tables.

When documenting the basis for inclusion of components into the appropriate levels of monitoring, as per Requirement R1 (Part 1.2~~4~~) of the standard, is it necessary to

provide this documentation about the device by listing of every component and the specific monitoring attributes of each device?

No. While maintaining this documentation on the device level would certainly be permissible, it is not necessary. Global statements can be made to document appropriate levels of monitoring for the entire population of a component type or portion thereof.

For example, it would be permissible to document the conclusion that all BES substation dc supply battery chargers are monitored by stating the following within the program description:

> "All substation dc supply battery chargers are considered monitored and subject to the rows for monitored equipment of Table 1-4 requirements, as all substation dc supply battery chargers are equipped with dc voltage alarms and ground detection alarms that are sent to the manned control center."

Similarly, it would be acceptable to use a combination of a global statement and a device-level list of exclusions. Example:

> "Except as noted below, all substation dc supply battery chargers are considered monitored and subject to the rows for monitored equipment of Table 1-4 requirements, as all substation dc supply battery chargers are equipped with dc voltage alarms and ground detection alarms that are sent to the manned control center. The dc supply battery chargers of Substation X, Substation Y, and Substation Z are considered unmonitored and subject to the rows for unmonitored equipment in Table 1-4 requirements, as they are not equipped with ground detection capability."

Regardless whether this documentation is provided by device listing of monitoring attributes, by global statements of the monitoring attributes of an entire population of component types, or by some combination of these methods, it should be noted that auditors may request supporting drawings or other documentation necessary to validate the inclusion of the device(s) within the appropriate level of monitoring. This supporting background information need not be maintained within the program document structure, but should be retrievable if requested by an auditor.

7. Time-Based Versus Condition-Based Maintenance

Time-based and condition-based (or monitored) maintenance programs are both acceptable, if implemented according to technically sound requirements. Practical programs can employ a *combination of time-based and condition-based maintenance.* The standard requirements introduce the concept of optionally using condition monitoring as a documented element of a maintenance program.

The Federal Energy Regulatory Commission (FERC), in its Order Number 693 Final Rule, dated March 16, 2007 (18 CFR Part 40, Docket No. RM06-16-000) on Mandatory Reliability Standards for the Bulk-Power System, directed NERC to submit a modification to PRC-005-1b that includes a requirement that maintenance and testing of a Protection System must be carried out within a maximum allowable interval that is appropriate to the type of the Protection System and its impact on the reliability of the Bulk Power System. Accordingly, this Supplementary Reference Paper refers to the specific maximum allowable intervals in PRC-005-4~~X~~. The defined time limits allow for longer time intervals if the maintained component is monitored.

A key feature of condition-based monitoring is that it effectively reduces the time delay between the moment of a protection failure and time the Protection System or Automatic Reclosing owner knows about it, for the monitored segments of the Protection System. In some cases, the verification is practically continuous - the time interval between verifications is minutes or seconds. Thus, technically sound, condition-based verification, meets the verification requirements of the FERC order even more effectively than the strictly time-based tests of the same system components.

The result is that:

This NERC standard permits utilities to use a technically sound approach and to take advantage of remote monitoring, data analysis, and control capabilities of modern Protection System and Automatic Reclosing Components to reduce the need for periodic site visits and invasive testing of components by on-site technicians. This periodic testing must be conducted within the maximum time intervals specified in the Tables of PRC-005-4~~X~~.

7.1 Frequently Asked Questions:

What is a Calendar Year?

Calendar Year - January 1 through December 31 of any year. As an example, if an event occurred on June 17, 2009 and is on a “One Calendar Year Interval,” the next event would have to occur on or before December 31, 2010.

Please provide an example of “4 Calendar Months”.

If a maintenance activity is described as being needed every four Calendar Months then it is performed in a (given) month and due again four months later. For example a battery bank is inspected in month number 1 then it is due again before the end of the month number5. And specifically consider that you perform your battery inspection on January 3, 2010 then it must be inspected again before the end of May. Another example could be that a four-month inspection was performed in January is due in May, but if performed in March (instead of May) would still be due four months later therefore the activity is due again July. Basically every "four Calendar Months" means to add four months from the last time the activity was performed.

Please provide an example of the unmonitored versus other levels of monitoring available?

An unmonitored Protection System has no monitoring and alarm circuits on the Protection System components. A Protection System component that has monitoring attributes but no alarm output connected is considered to be unmonitored.

A monitored Protection System or an individual monitored component of a Protection System has monitoring and alarm circuits on the Protection System components. The alarm circuits must alert, within 24 hours, a location wherein corrective action can be initiated. This location might be, but is not limited to, an Operations Center, Dispatch Office, Maintenance Center or even a portable SCADA system.

There can be a combination of monitored and unmonitored Protection Systems within any given scheme, substation or plant; there can also be a combination of monitored and unmonitored components within any given Protection System.

Example #1: A combination of monitored and unmonitored components within a given Protection System might be:

- A microprocessor relay with an internal alarm connected to SCADA to alert 24-hr staffed operations center; it has internal self-diagnosis and alarming. (monitored)
- Instrumentation transformers, with no monitoring, connected as inputs to that relay. (unmonitored)
- A vented Lead-Acid battery with a low voltage alarm for the station dc supply voltage and an unintentional grounds detection alarm connected to SCADA. (monitoring varies)
- A circuit breaker with a trip coil, and the trip circuit is not monitored. (unmonitored)

Given the particular components and conditions, and using Table 1 and Table 2, the particular components have maximum activity intervals of:

Every four calendar months, inspect:

- Electrolyte level (station dc supply voltage and unintentional ground detection is being maintained more frequently by the monitoring system).

Every 18 calendar months, verify/inspect the following:

- Battery bank ohmic values to station battery baseline (if performance tests are not opted)
- Battery charger float voltage
- Battery rack integrity
- Cell condition of all individual battery cells (where visible)
- Battery continuity
- Battery terminal connection resistance

- Battery cell-to-cell resistance (where available to measure)

Every six calendar years, perform/verify the following:

- Battery performance test (if internal ohmic tests or other measurements indicative of battery performance are not opted)
- Verify that each trip coil is able to operate the circuit breaker, interrupting device, or mitigating device
- For electromechanical lock-out relays, electrical operation of electromechanical trip

Every 12 calendar years, verify the following:

- Microprocessor relay settings are as specified
- Operation of the microprocessor's relay inputs and outputs that are essential to proper functioning of the Protection System
- Acceptable measurement of power System input values seen by the microprocessor protective relay
- Verify that current and voltage signal values are provided to the protective relays
- Protection System component monitoring for the battery system signals are conveyed to a location where corrective action can be initiated
- The microprocessor relay alarm signals are conveyed to a location where corrective action can be initiated
- Verify all trip paths in the control circuitry associated with protective functions through the trip coil(s) of the circuit breakers or other interrupting devices
- Auxiliary outputs that are in the trip path shall be maintained as detailed in Table 1-5 of the standard under the 'Unmonitored Control Circuitry Associated with Protective Functions" section'
- Auxiliary outputs not in a trip path (i.e., annunciation or DME input) are not required, by this standard, to be checked

Example #2: A combination of monitored and unmonitored components within a given Protection System might be:

- A microprocessor relay with integral alarm that is not connected to SCADA. (unmonitored)
- Current and voltage signal values, with no monitoring, connected as inputs to that relay. (unmonitored)
- A vented lead-acid battery with a low voltage alarm for the station dc supply voltage and an unintentional grounds detection alarm connected to SCADA. (monitoring varies)
- A circuit breaker with a trip coil, with no circuits monitored. (unmonitored)

Given the particular components and conditions, and using the Table 1 (Maximum Allowable Testing Intervals and Maintenance Activities) and Table 2 (Alarming Paths and Monitoring), the particular components have maximum activity intervals of:

Every four calendar months, inspect:

- Electrolyte level (station dc supply voltage and unintentional ground detection is being maintained more frequently by the monitoring system)

Every 18 calendar months, verify/inspect the following:

- Battery bank trending of ohmic values or other measurements indicative of battery performance to station battery baseline (if performance tests are not opted)
- Battery charger float voltage
- Battery rack integrity
- Cell condition of all individual battery cells (where visible)
- Battery continuity
- Battery terminal connection resistance
- Battery cell-to-cell resistance (where available to measure)

Every six calendar years, verify/perform the following:

- Verify operation of the relay inputs and outputs that are essential to proper functioning of the Protection System
- Verify acceptable measurement of power system input values as seen by the relays
- Verify that each trip coil is able to operate the circuit breaker, interrupting device, or mitigating device
- For electromechanical lock-out relays, electrical operation of electromechanical trip
- Battery performance test (if internal ohmic tests are not opted)

Every 12 calendar years, verify the following:

- Current and voltage signal values are provided to the protective relays
- Protection System component monitoring for the battery system signals are conveyed to a location where corrective action can be initiated
- All trip paths in the control circuitry associated with protective functions through the trip coil(s) of the circuit breakers or other interrupting devices
- Auxiliary outputs that are in the trip path shall be maintained, as detailed in Table 1-5 of the standard under the Unmonitored Control Circuitry Associated with Protective Functions" section
- Auxiliary outputs not in a trip path (i.e., annunciation or DME input) are not required, by this standard, to be checked

Example #3: A combination of monitored and unmonitored components within a given Protection System might be:

- A microprocessor relay with alarm connected to SCADA to alert 24-hr staffed operations center; it has internal self-diagnosis and alarms. (monitored)

- Current and voltage signal values, with monitoring, connected as inputs to that relay (monitored)
- Vented Lead-Acid battery without any alarms connected to SCADA (unmonitored)
- Circuit breaker with a trip coil, with no circuits monitored (unmonitored)

Given the particular components, conditions, and using the Table 1 (Maximum Allowable Testing Intervals and Maintenance Activities) and Table 2 (Alarming Paths and Monitoring), the particular components shall have maximum activity intervals of:

Every four calendar months, verify/inspect the following:

- Station dc supply voltage
- For unintentional grounds
- Electrolyte level

Every 18 calendar months, verify/inspect the following:

- Battery bank trending of ohmic values or other measurements indicative of battery performance to station battery baseline (if performance tests are not opted)
- Battery charger float voltage
- Battery rack integrity
- Battery continuity
- Battery terminal connection resistance
- Battery cell-to-cell resistance (where available to measure)
- Condition of all individual battery cells (where visible)

Every six calendar years, perform/verify the following:

- Battery performance test (if internal ohmic tests or other measurements indicative of battery performance are not opted)
- Verify that each trip coil is able to operate the circuit breaker, interrupting device, or mitigating device
- For electromechanical lock-out relays, electrical operation of electromechanical trip

Every 12 calendar years, verify the following:

- The microprocessor relay alarm signals are conveyed to a location where corrective action can be taken
- Microprocessor relay settings are as specified
- Operation of the microprocessor's relay inputs and outputs that are essential to proper functioning of the Protection System
- Acceptable measurement of power system input values seen by the microprocessor protective relay

- Verify all trip paths in the control circuitry associated with protective functions through the trip coil(s) of the circuit breakers or other interrupting devices
- Auxiliary outputs that are in the trip path shall be maintained, as detailed in Table 1-5 of the standard under the Unmonitored Control Circuitry Associated with Protective Functions section
- Auxiliary outputs not in a trip path (i.e. annunciation or DME input) are not required, by this standard, to be checked

Why do components have different maintenance activities and intervals if they are monitored?

The intent behind different activities and intervals for monitored equipment is to allow less frequent manual intervention when more information is known about the condition of Protection System components. Condition-Based Maintenance is a valuable asset to improve reliability.

Can all components in a Protection System be monitored?

No. For some components in a Protection System, monitoring will not be relevant. For example, a battery will always need some kind of inspection.

We have a 30-year-old oil circuit breaker with a red indicating lamp on the substation relay panel that is illuminated only if there is continuity through the breaker trip coil. There is no SCADA monitor or relay monitor of this trip coil. The line protection relay package that trips this circuit breaker is a microprocessor relay that has an integral alarm relay that will assert on a number of conditions that includes a loss of power to the relay. This alarm contact connects to our SCADA system and alerts our 24-hour operations center of relay trouble when the alarm contact closes. This microprocessor relay trips the circuit breaker only and does not monitor trip coil continuity or other things such as trip current. Are the components monitored or not? How often must I perform maintenance?

The protective relay is monitored and can be maintained every 12 years, or when an Unresolved Maintenance Issue arises. The control circuitry can be maintained every 12 years. The circuit breaker trip coil(s) has to be electrically operated at least once every six years.

What is a mitigating device?

A mitigating device is the device that acts to respond as directed by a ~~Special Protection System~~Remedial Action System. It may be a breaker, valve, distributed control system, or any variety of other devices. This response may include tripping, closing, or other control actions.

8. Maximum Allowable Verification Intervals

The maximum allowable testing intervals and maintenance activities show how CBM with newer device types can reduce the need for many of the tests and site visits that older Protection System components require. As explained below, there are some sections of the Protection System that monitoring or data analysis may not verify. Verifying these sections of the Protection System or Automatic Reclosing requires some persistent TBM activity in the maintenance program. However, some of this TBM can be carried out remotely - for example, exercising a circuit breaker through the relay tripping circuits using the relay remote control capabilities can be used to verify function of one tripping path and proper trip coil operation, if there has been no Fault or routine operation to demonstrate performance of relay tripping circuits.

8.1 Maintenance Tests

Periodic maintenance testing is performed to ensure that the protection and control system is operating correctly after a time period of field installation. These tests may be used to ensure that individual components are still operating within acceptable performance parameters - this type of test is needed for components susceptible to degraded or changing characteristics due to aging and wear. Full system performance tests may be used to confirm that the total Protection System functions from measurement of power system values, to properly identifying Fault characteristics, to the operation of the interrupting devices.

8.1.1 Table of Maximum Allowable Verification Intervals

Table 1 (collectively known as Table 1, individually called out as Tables 1-1 through 1-5), Table 2, Table 3, Table 4-1 through Table 4-2, and Table 5 in the standard specify maximum allowable verification intervals for various generations of Protection Systems, Automatic Reclosing and Sudden Pressure Relaying and categories of equipment that comprise these systems. The right column indicates maintenance activities required for each category.

The types of components are illustrated in Figures 1 and 2 at the end of this paper. Figure 1 shows an example of telecommunications-assisted transmission Protection System comprising substation equipment at each terminal and a telecommunications channel for relaying between the two substations. Figure 2 shows an example of a generation Protection System. The various sub-systems of a Protection System that need to be verified are shown.

Non-distributed UFLS, UVLS, and ~~SPS~~ RAS are additional categories of Table 1 that are not illustrated in these figures. Non-distributed UFLS, UVLS and ~~SPS~~ RAS all use identical equipment as Protection Systems in the performance of their functions; and, therefore, have the same maintenance needs.

Distributed UFLS and UVLS Systems, which use local sensing on the distribution System and trip co-located non-BES interrupting devices, are addressed in Table 3 with reduced maintenance activities.

While it is easy to associate protective relays to multiple levels of monitoring, it is also true that most of the components that can make up a Protection System can also have technological advancements that place them into higher levels of monitoring.

To use the Maintenance Activities and Intervals Tables from PRC-005-4~~X~~:

- First find the Table associated with your component. The tables are arranged in the order of mention in the definition of Protection System;
    - Table 1-1 is for protective relays,
    - Table 1-2 is for the associated communications systems,
    - Table 1-3 is for current and voltage sensing devices,
    - Table 1-4 is for station dc supply and
    - Table 1-5 is for control circuits.
    - Table 2, is for alarms; this was broken out to simplify the other tables.
    - Table 3 is for components which make-up distributed UFLS and UVLS Systems.
    - Table 4 is for Automatic Reclosing.
    - Table 5 is for Sudden Pressure Relaying.
- Next look within that table for your device and its degree of monitoring. The Tables have different hands-on maintenance activities prescribed depending upon the degree to which you monitor your equipment. Find the maintenance activity that applies to the monitoring level that you have on your piece of equipment.
- This Maintenance activity is the minimum maintenance activity that must be documented.
- If your Performance-Based Maintenance (PBM) plan requires more activities, then you must perform and document to this higher standard. (Note that this does not apply unless you utilize PBM.)
- After the maintenance activity is known, check the maximum maintenance interval; this time is the maximum time allowed between hands-on maintenance activity cycles of this component.
- If your Performance-Based Maintenance plan requires activities more often than the Tables maximum, then you must perform and document those activities to your more stringent standard. (Note that this does not apply unless you utilize PBM.)
- Any given component of a Protection System can be determined to have a degree of monitoring that may be different from another component within that same Protection System. For example, in a given Protection System it is possible for an entity to have a monitored protective relay and an unmonitored associated communications system; this combination would require hands-on maintenance activity on the relay at least once every 12 years and attention paid to the communications system as often as every four months.
- An entity does not have to utilize the extended time intervals made available by this use of condition-based monitoring. An easy choice to make is to simply utilize the unmonitored level of maintenance made available in each of the Tables. While the maintenance activities resulting from this choice would require more maintenance man-

hours, the maintenance requirements may be simpler to document and the resulting maintenance plans may be easier to create.

For each Protection System Component, Table 1 shows maximum allowable testing intervals for the various degrees of monitoring. For each Automatic Reclosing Component, Table 4 shows maximum allowable testing intervals for the various degrees of monitoring. These degrees of monitoring, or levels, range from the legacy unmonitored through a system that is more comprehensively monitored.

It has been noted here that an entity may have a PSMP that is more stringent than PRC-005-4~~X~~. There may be any number of reasons that an entity chooses a more stringent plan than the minimums prescribed within PRC-005-4~~X~~, most notable of which is an entity using performance based maintenance methodology.

If an entity has a Performance-Based Maintenance program, then that plan must be followed, even if the plan proves to be more stringent than the minimums laid out in the Tables.

If an entity has a Time-Based Maintenance program and the PSMP is more stringent than PRC-005-4~~X~~, they will only be audited in accordance with the standard (minimum maintenance activities and maximum maintenance intervals prescribed within Tables 1-1 through 1-5, Table 2, Table 3, Table 4-1 through 4-2, and Table 5).

8.1.2 Additional Notes for Tables 1-1 through 1-5, Table 3, and Table 4

1. For electromechanical relays, adjustment is required to bring measurement accuracy within the tolerance needed by the asset owner. Microprocessor relays with no remote monitoring of alarm contacts, etc., are unmonitored relays and need to be verified within the Table interval as other unmonitored relays but may be verified as functional by means other than testing by simulated inputs.

2. Microprocessor relays typically are specified by manufacturers as not requiring calibration, but acceptable measurement of power system input values must be verified (verification of the Analog to Digital [A/D] converters) within the Table intervals. The integrity of the digital inputs and outputs that are used as protective functions must be verified within the Table intervals.

3. Any Phasor Measurement Unit (PMU) function whose output is used in a Protection System or ~~SPS~~ RAS (as opposed to a monitoring task) must be verified as a component in a Protection System.

4. In addition to verifying the circuitry that supplies dc to the Protection System, the owner must maintain the station dc supply. The most widespread station dc supply is the station battery and charger. Unlike most Protection System components, physical inspection of station batteries for signs of component failure, reduced performance, and degradation are required to ensure that the station battery is reliable enough to deliver dc power when required. IEEE Standards 450, 1188, and 1106 for vented lead-acid, valve-regulated lead-acid, and nickel-cadmium batteries, respectively (which are the most commonly used substation batteries on the NERC BES) have been developed as an important reference source of maintenance recommendations. The Protection System owner might want to follow the guidelines in the applicable IEEE recommended practices for battery maintenance and testing, especially if the battery in question is used for application requirements in addition to the protection and control demands

covered under this standard. However, the Standard Drafting Team has tailored the battery maintenance and testing guidelines in PRC-005-4~~X~~ for the Protection System owner which are application specific for the BES Facilities. While the IEEE recommendations are all encompassing, PRC-005-4~~X~~ is a more economical approach while addressing the reliability requirements of the BES.

5. Aggregated small entities might distribute the testing of the population of UFLS/UVLS systems, and large entities will usually maintain a portion of these systems in any given year. Additionally, if relatively small quantities of such systems do not perform properly, it will not affect the integrity of the overall program. Thus, these distributed systems have decreased requirements as compared to other Protection Systems.

6. Voltage & current sensing device circuit input connections to the Protection System relays can be verified by (but not limited to) comparison of measured values on live circuits or by using test currents and voltages on equipment out of service for maintenance. The verification process can be automated or manual. The values should be verified to be as expected (phase value and phase relationships are both equally important to verify).

7. "End-to-end test," as used in this Supplementary Reference, is any testing procedure that creates a remote input to the local communications-assisted trip scheme. While this can be interpreted as a GPS-type functional test, it is not limited to testing via GPS. Any remote scheme manipulation that can cause action at the local trip path can be used to functionally-test the dc control circuitry. A documented Real-time trip of any given trip path is acceptable in lieu of a functional trip test. It is possible, with sufficient monitoring, to be able to verify each and every parallel trip path that participated in any given dc control circuit trip. Or another possible solution is that a single trip path from a single monitored relay can be verified to be the trip path that successfully tripped during a Real-time operation. The variations are only limited by the degree of engineering and monitoring that an entity desires to pursue.

8. A/D verification may use relay front panel value displays, or values gathered via data communications. Groupings of other measurements (such as vector summation of bus feeder currents) can be used for comparison if calibration requirements assure acceptable measurement of power system input values.

9. Notes 1-8 attempt to describe some testing activities; they do not represent the only methods to achieve these activities, but rather some possible methods. Technological advances, ingenuity and/or industry accepted techniques can all be used to satisfy maintenance activity requirements; the standard is technology- and method-neutral in most cases.

8.1.3 Frequently Asked Questions:

What is meant by "Verify that settings are as specified" maintenance activity in Table 1-1?

Verification of settings is an activity directed mostly towards microprocessor- based relays. For relay maintenance departments that choose to test microprocessor-based relays in the same manner as electromechanical relays are tested, the testing process sometimes requires that some specific functions be disabled. Later tests might enable the functions previously disabled, but perhaps still other functions or logic statements were then masked out. It is imperative that, when the relay is placed into service, the settings in the relay be the settings that were intended to be in that relay or as the standard states "…settings are as specified."

Many of the microprocessor- based relays available today have software tools which provide this functionality and generate reports for this purpose.

For evidence or documentation of this requirement, a simple recorded acknowledgement that the settings were checked to be as specified is sufficient.

The drafting team was careful not to require "…that the relay settings be correct…" because it was believed that this might then place a burden of proof that the specified settings would result in the correct intended operation of the interrupting device. While that is a noble intention, the measurable proof of such a requirement is immense. The intent is that settings of the component be as specified at the conclusion of maintenance activities, whether those settings may have "drifted" since the prior maintenance or whether changes were made as part of the testing process.

Are electromechanical relays included in the "Verify that settings are as specified" maintenance activity in Table 1-1?

Verification of settings is an activity directed towards the application of protection related functions of microprocessor based relays. Electromechanical relays require calibration verification by voltage and/or current injection; and, thus, the settings are verified during calibration activity. In the example of a time-overcurrent relay, a minor deviation in time dial, versus the settings, may be acceptable, as long as the relay calibration is within accepted tolerances at the injected current amplitudes. A major deviation may require further investigation, as it could indicate a problem with the relay or an incorrect relay style for the application.

The verification of phase current and voltage measurements by comparison to other quantities seems reasonable. How, though, can I verify residual or neutral currents, or 3V0 voltages, by comparison, when my system is closely balanced?

Since these inputs are verified at commissioning, maintenance verification requires ensuring that phase quantities are as expected and that 3IO and 3VO quantities appear equal to or close to 0.

These quantities also may be verified by use of oscillographic records for connected microprocessor relays as recorded during system Disturbances. Such records may compare to similar values recorded at other locations by other microprocessor relays for the same event, or compared to expected values (from short circuit studies) for known Fault locations.

What does this Standard require for testing an auxiliary tripping relay?

Table 1 and Table 3 requires that a trip test must verify that the auxiliary tripping relay(s) and/or lockout relay(s) which are directly in a trip path from the protective relay to the interrupting device trip coil operate(s) electrically. Auxiliary outputs not in a trip path (i.e. annunciation or DME input) are not required, by this standard, to be checked.

Do I have to perform a full end-to-end test of a ~~Special Protection System~~Remedial Action System?

No. All portions of the ~~SPS~~ -RAS need to be maintained, and the portions must overlap, but the overall ~~SPS~~ RAS does not need to have a single end-to-end test. In other words it may be tested in piecemeal fashion provided all of the pieces are verified.

What about ~~SPS~~RAS interfaces between different entities or owners?

As in all of the Protection System requirements, ~~SPS~~ RAS segments can be tested individually, thus minimizing the need to accommodate complex maintenance schedules.

What do I have to do if I am using a phasor measurement unit (PMU) as part of a Protection System or ~~Special Protection System~~Remedial Action System?

Any Phasor Measurement Unit (PMU) function whose output is used in a Protection System or ~~Special Protection System~~Remedial Action System (as opposed to a monitoring task) must be verified as a component in a Protection System.

How do I maintain a ~~Special Protection System~~Remedial Action System or relay sensing for non-distributed UFLS or UVLS Systems?

Since components of the RAS~~SPS~~, UFLS and UVLS are the same types of components as those in Protection Systems, then these components should be maintained like similar components used for other Protection System functions. In many cases the devices for ~~SPS,~~RAS, UFLS and UVLS are also used for other protective functions. The same maintenance activities apply with the exception that distributed systems (UFLS and UVLS) have fewer dc supply and control circuitry maintenance activity requirements.

For the testing of the output action, verification may be by breaker tripping, but may be verified in overlapping segments. For example, an ~~SPS~~ RAS that trips a remote circuit breaker might be tested by testing the various parts of the scheme in overlapping segments. Another method is to document the Real-time tripping of an ~~SPS~~ RAS scheme should that occur. Forced trip tests of circuit breakers (etc.) that are a part of distributed UFLS or UVLS schemes are not required.

The established maximum allowable intervals do not align well with the scheduled outages for my power plant. Can I extend the maintenance to the next scheduled outage following the established maximum interval?

No. You must complete your maintenance within the established maximum allowable intervals in order to be compliant. You will need to schedule your maintenance during available outages to complete your maintenance as required, even if it means that you may do protective relay maintenance more frequently than the maximum allowable intervals. The maintenance intervals were selected with typical plant outages, among other things, in mind.

If I am unable to complete the maintenance, as required, due to a major natural disaster (hurricane, earthquake, etc.), how will this affect my compliance with this standard?

The Sanction Guidelines of the North American Electric Reliability Corporation, effective January 15, 2008, provides that the Compliance Monitor will consider extenuating circumstances when considering any sanctions.

What if my observed testing results show a high incidence of out-of-tolerance relays; or, even worse, I am experiencing numerous relay Misoperations due to the relays being out-of-tolerance?

The established maximum time intervals are mandatory only as a not-to-exceed limitation. The establishment of a maximum is measurable. But any entity can choose to test some or all of their Protection System components more frequently (or to express it differently, exceed the minimum requirements of the standard). Particularly if you find that the maximum intervals in the standard do not achieve your expected level of performance, it is understandable that you would maintain the related equipment more frequently. A high incidence of relay Misoperations is in no one's best interest.

We believe that the four-month interval between inspections is unneccessary. Why can we not perform these inspections twice per year?

The Standard Drafting Team, through the comment process, has discovered that routine monthly inspections are not the norm. To align routine station inspections with other important inspections, the four-month interval was chosen. In lieu of station visits, many activities can be accomplished with automated monitoring and alarming.

Our maintenance plan calls for us to perform routine protective relay tests every 3 years. If we are unable to achieve this schedule, but we are able to complete the procedures in less than the maximum time interval ,then are we in or out of compliance?

According to R3, if you have a time-based maintenance program, then you will be in violation of the standard only if you exceed the maximum maintenance intervals prescribed in the Tables. According to R4, if your device in question is part of a Performance-Based Maintenance program, then you will be in violation of the standard if you fail to meet your PSMP, even if you do not exceed the maximum maintenance intervals prescribed in the Tables. The intervals in the Tables are associated with TBM and CBM; Attachment A is associated with PBM.

Please provide a sample list of devices or systems that must be verified in a generator, generator step-up transformer, generator connected station service or generator connected excitation transformer to meet the requirements of this maintenance standard.

Examples of typical devices and systems that may directly trip the generator, or trip through a lockout relay, may include, but are not necessarily limited to:

- Fault protective functions, including distance functions, voltage-restrained overcurrent functions, or voltage-controlled overcurrent functions
- Loss-of-field relays
- Volts-per-hertz relays
- Negative sequence overcurrent relays
- Over voltage and under voltage protection relays
- Stator-ground relays
- Communications-based Protection Systems such as transfer-trip systems
- Generator differential relays
- Reverse power relays
- Frequency relays

- Out-of-step relays
- Inadvertent energization protection
- Breaker failure protection

For generator step-up, generator-connected station service transformers, or generator connected excitation transformers, operation of any of the following associated protective relays frequently would result in a trip of the generating unit; and, as such, would be included in the program:

- Transformer differential relays
- Neutral overcurrent relay
- Phase overcurrent relays

Relays which trip breakers serving station auxiliary Loads such as pumps, fans, or fuel handling equipment, etc., need not be included in the program, even if the loss of the those Loads could result in a trip of the generating unit. Furthermore, relays which provide protection to secondary unit substation (SUS) or low switchgear transformers and relays protecting other downstream plant electrical distribution system components are not included in the scope of this program, even if a trip of these devices might eventually result in a trip of the generating unit. For example, a thermal overcurrent trip on the motor of a coal-conveyor belt could eventually lead to the tripping of the generator, but it does not cause the trip.

In the case where a plant does not have a generator connected station service transformer such that it is normally fed from a system connected station service transformer, is it still the drafting team's intent to exclude the Protection Systems for these system connected auxiliary transformers from scope even when the loss of the normal (system connected) station service transformer will result in a trip of a BES generating Facility?

The SDT does not intend that the system-connected station service transformers be included in the Applicability. The generator-connected station service transformers and generator connected excitation transformers are often connected to the generator bus directly without an interposing breaker; thus, the Protection Systems on these transformers will trip the generator as discussed in 4.2.5.1.

What is meant by "verify operation of the relay inputs and outputs that are essential to proper functioning of the Protection System?"

Any input or output (of the relay) that "affects the tripping" of the breaker is included in the scope of I/O of the relay to be verified. By "affects the tripping," one needs to realize that sometimes there are more inputs and outputs than simply the output to the trip coil. Many important protective functions include things like breaker fail initiation, zone timer initiation and sometimes even 52a/b contact inputs are needed for a protective relay to correctly operate.

Each input should be "picked up" or "turned on and off" and verified as changing state by the microprocessor of the relay. Each output should be "operated" or "closed and opened" from the microprocessor of the relay and the output should be verified to change state on the output terminals of the relay. One possible method of testing inputs of these relays is to "jumper" the needed dc voltage to the input and verify that the relay registered the change of state.

Electromechanical lock-out relays (86) (used to convey the tripping current to the trip coils) need to be electrically operated to prove the capability of the device to change state. These tests need to be accomplished at least every six years, unless PBM methodology is applied.

The contacts on the 86 or auxiliary tripping relays (94) that change state to pass on the trip current to a breaker trip coil need only be checked every 12 years with the control circuitry.

What is the difference between a distributed UFLS/UVLS and a non-distributed UFLS/UVLS scheme?

A distributed UFLS or UVLS scheme contains individual relays which make independent Load shed decisions based on applied settings and localized voltage and/or current inputs. A distributed scheme may involve an enable/disable contact in the scheme and still be considered a distributed scheme. A non-distributed UFLS or UVLS scheme involves a system where there is some type of centralized measurement and Load shed decision being made. A non-distributed UFLS/UVLS scheme is considered similar to an ~~SPS~~ RAS scheme and falls under Table 1 for maintenance activities and intervals.

8.2 Retention of Records

PRC-005-1 describes a reporting or auditing cycle of one year and retention of records for three years. However, with a three-year retention cycle, the records of verification for a Protection System might be discarded before the next verification, leaving no record of what was done if a Misoperation or failure is to be analyzed.

PRC-005-4~~X~~ corrects this by requiring:

The Transmission Owner, Generator Owner, and Distribution Provider shall each keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

For Requirement R1, the Transmission Owner, Generator Owner, and Distribution Provider shall each keep its current dated Protection System Maintenance Program, as well as any superseded versions since the preceding compliance audit, including the documentation that specifies the type of maintenance program applied for each Protection System, Automatic Reclosing, or Sudden Pressure Relaying Component Type.

For Requirement R2, Requirement R3, and Requirement R4, in cases where the interval of the maintenance activity is longer than the audit cycle, the Transmission Owner, Generator Owner, and Distribution Provider shall each keep documentation of the most recent performance of that maintenance activity for the Protection System, Automatic Reclosing, or Sudden Pressure Relaying Component. In cases where the interval of the maintenance activity is shorter than the audit cycle, documentation of all performances (in accordance with the tables) of that maintenance activity for the Protection System, Automatic Reclosing, or Sudden Pressure Relaying Component since the previous scheduled audit date shall be retained.

For Requirement R5 the Transmission Owner, Generator Owner, and Distribution Provider shall each keep documentation of Unresolved Maintenance Issues ~~encountered~~ identified by the entity since the last audit, including all that were resolved since the last audit.

~~*The Transmission Owner, Generator Owner, and Distribution Provider shall each retain documentation of the most recent performance of each distinct maintenance activity for the Protection System, Automatic Reclosing, or Sudden Pressure Relaying Component, or to the previous scheduled (on-site) audit date, whichever is longer.*~~

This requirement assures that the documentation shows that the interval between maintenance cycles correctly meets the maintenance interval limits. The requirement is actually alerting the industry to documentation requirements already implemented by audit teams. Evidence of compliance bookending the interval shows interval accomplished instead of proving only your planned interval.

The SDT is aware that, in some cases, the retention period could be relatively long. But, the retention of documents simply helps to demonstrate compliance.

8.2.1 Frequently Asked Questions:

Please clarify the data retention requirements.

The data retention requirements are intended to allow the availability of maintenance records to demonstrate that the time intervals in your maintenance plan were upheld.

Maximum Maintenance Interval	Data Retention Period
4 Months, 6 Months,18 Months, or 3 Years	All activities since previous audit
6 Years	All activities since previous audit(assuming a 6 year audit cycle) or most recent performance(assuming 3 year audit cycle), whichever is longer
12 Year	All activities from the most recent performance

If an entity prefers to utilize Performance-Based Maintenance, then statistical data may well be retained for extended periods to assist with future adjustments in time intervals.

If an equipment item is replaced, then the entity can restart the maintenance-time-interval-clock if desired; however, the replacement of equipment does not remove any documentation requirements that would have been required to verify compliance with time-interval requirements. In other words, do not discard maintenance data that goes to verify your work.

The retention of documentation for new and/or replaced equipment is all about proving that the maintenance intervals had been in compliance. For example, a long-range plan of upgrades might lead an entity to ignore required maintenance; retaining the evidence of prior maintenance that existed before any retirements and upgrades proves compliance with the standard.

What does this Maintenance Standard say about commissioning? Is it necessary to have documentation in your maintenance history of the completion of commission testing?

This standard does not establish requirements for commission testing. Commission testing includes all testing activities necessary to conclude that a Facility has been built in accordance with design. While a thorough commission testing program would include, either directly or indirectly, the verification of all those Protection System attributes addressed by the maintenance activities specified in the Tables of PRC-005-4~~X~~, verification of the adequacy of initial installation necessitates the performance of testing and inspections that go well beyond these routine maintenance activities. For example, commission testing might set baselines for future tests; perform acceptance tests and/or warranty tests; utilize testing methods that are not generally done routinely like staged-Fault-tests.

However, many of the Protection System attributes which are verified during commission testing are not subject to age related or service related degradation, and need not be re-verified within an ongoing maintenance program. Example – it is not necessary to re-verify correct terminal strip wiring on an ongoing basis.

PRC-005-4~~X~~ assumes that thorough commission testing was performed prior to a Protection System being placed in service. PRC-005-4~~X~~ 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.

It should be noted that commission testing frequently is performed by a different organization than that which is responsible for the ongoing maintenance of the Protection System. Furthermore, the commission testing activities will not necessarily correlate directly with the maintenance activities required by the standard. As such, it is very likely that commission testing records will deviate significantly from maintenance records in both form and content; and, therefore, it is not necessary to maintain commission testing records within the maintenance program documentation.

Notwithstanding the differences in records, an entity would be wise to retain commissioning records to show a maintenance start date. (See below). An entity that requires that their commissioning tests have, at a minimum, the requirements of PRC-005-4~~X~~ would help that entity prove time interval maximums by setting the initial time clock.

How do you determine the initial due date for maintenance?

The initial due date for maintenance should be based upon when a Protection System was tested. Alternatively, an entity may choose to use the date of completion of the commission testing of the Protection System component and the system was placed into service as the starting point in determining its first maintenance due dates. Whichever method is chosen, for newly installed Protection Systems the components should not be placed into service until minimum maintenance activities have taken place.

It is conceivable that there can be a (substantial) difference in time between the date of testing, as compared to the date placed into service. The use of the "Calendar Year" language can help determine the next due date without too much concern about being non-compliant for missing test dates by a small amount (provided your dates are not already at the end of a year). However, if there is a substantial amount of time difference between testing and in-service dates, then the testing date should be followed because it is the degradation of components that is the concern. While accuracy fluctuations may decrease when components are not energized, there are cases when degradation can take place, even though the device is not energized. Minimizing the time between commissioning tests and in-service dates will help.

If I miss two battery inspections four times out of 100 Protection System components on my transmission system, does that count as 2% or 8% when counting Violation Severity Level (VSL) for R3?

The entity failed to complete its scheduled program on two of its 100 Protection System components, which would equate to 2% for application to the VSL Table for Requirement R3. This VSL is written to compare missed components to total components. In this case two components out of 100 were missed, or 2%.

How do I achieve a "grace period" without being out of compliance?

The objective here is to create a time extension within your own PSMP that still does not violate the maximum time intervals stated in the standard. Remember that the maximum time intervals listed in the Tables cannot be extended.

For the purposes of this example, concentrating on just unmonitored protective relays – Table 1-1 specifies a maximum time interval (between the mandated maintenance activities) of six calendar years. Your plan must ensure that your unmonitored relays are tested at least once every six calendar years. You could, within your PSMP, require that your unmonitored relays be tested every four calendar years, with a maximum allowable time extension of 18 calendar months. This allows an entity to have deadlines set for the auto-generation of work orders, but still has the flexibility in scheduling complex work schedules. This also allows for that 18 calendar months to act as a buffer, in effect a grace period within your PSMP, in the event of unforeseen events. You will note that this example of a maintenance plan interval has a planned time of four years; it also has a built-in time extension allowed within the PSMP, and yet does not exceed the maximum time interval allowed by the standard. So while there are no time extensions allowed beyond the standard, an entity can still have substantial flexibility to maintain their Protection System components.

8.3 Basis for Table 1 Intervals

When developing the original *Protection System Maintenance – A Technical Reference* in 2007, the SPCTF collected all available data from Regional Entities (REs) on time intervals recommended for maintenance and test programs. The recommendations vary widely in categorization of relays, defined maintenance actions, and time intervals, precluding development of intervals by averaging. The SPCTF also reviewed the 2005 Report [2] of the IEEE Power System Relaying Committee Working Group I-17 (Transmission Relay System Performance Comparison). Review of the I-17 report shows data from a small number of utilities, with no company identification or means of investigating the significance of particular results.

To develop a solid current base of practice, the SPCTF surveyed its members regarding their maintenance intervals for electromechanical and microprocessor relays, and asked the members to also provide definitively-known data for other entities. The survey represented 470 GW of peak Load, or 4% of the NERC peak Load. Maintenance interval averages were compiled by weighting reported intervals according to the size (based on peak Load) of the reporting utility. Thus, the averages more accurately represent practices for the large populations of Protection Systems used across the NERC regions.

The results of this survey with weighted averaging indicate maintenance intervals of five years for electromechanical or solid state relays, and seven years for unmonitored microprocessor relays.

A number of utilities have extended maintenance intervals for microprocessor relays beyond seven years, based on favorable experience with the particular products they have installed. To provide a technical basis for such extension, the SPCTF authors developed a recommendation of 10 years using the Markov modeling approach from [1], as summarized in Section 8.4. The results of this modeling depend on the completeness of self-testing or monitoring. Accordingly, this extended interval is allowed by Table 1, only when such relays are monitored as specified in the attributes of monitoring contained in Tables 1-1 through 1-5 and Table 2. Monitoring is capable of reporting Protection System health issues that are likely to affect performance within the 10 year time interval between verifications.

It is important to note that, according to modeling results, Protection System availability barely changes as the maintenance interval is varied below the 10-year mark. Thus, reducing the maintenance interval does not improve Protection System availability. With the assumptions of the model regarding how maintenance is carried out, reducing the maintenance interval actually degrades Protection System availability.

8.4 Basis for Extended Maintenance Intervals for Microprocessor Relays

Table 1 allows maximum verification intervals that are extended based on monitoring level. The industry has experience with self-monitoring microprocessor relays that leads to the Table 1 value for a monitored relay, as explained in Section 8.3. To develop a basis for the maximum interval for monitored relays in their *Protection System Maintenance – A Technical Reference*, the SPCTF used the methodology of Reference [1], which specifically addresses optimum routine maintenance intervals. The Markov modeling approach of [1] is judged to be valid for the design and typical failure modes of microprocessor relays.

The SPCTF authors ran test cases of the Markov model to calculate two key probability measures:

- Relay Unavailability - the probability that the relay is out of service due to failure or maintenance activity while the power system Element to be protected is in service.
- Abnormal Unavailability - the probability that the relay is out of service due to failure or maintenance activity when a Fault occurs, leading to failure to operate for the Fault.

The parameter in the Markov model that defines self-monitoring capability is ST (for self-test). ST = 0 if there is no self-monitoring; ST = 1 for full monitoring. Practical ST values are estimated to range from .75 to .95. The SPCTF simulation runs used constants in the Markov model that were the same as those used in [1] with the following exceptions:

Sn, Normal tripping operations per hour = 21600 (reciprocal of normal Fault clearing time of 10 cycles)

Sb, Backup tripping operations per hour = 4320 (reciprocal of backup Fault clearing time of 50 cycles)

Rc, Protected component repairs per hour = 0.125 (8 hours to restore the power system)

Rt, Relay routine tests per hour = 0.125 (8 hours to test a Protection System)

Rr, Relay repairs per hour = 0.08333 (12 hours to complete a Protection System repair after failure)

Experimental runs of the model showed low sensitivity of optimum maintenance interval to these parameter adjustments.

The resulting curves for relay unavailability and abnormal unavailability versus maintenance interval showed a broad minimum (optimum maintenance interval) in the vicinity of 10 years – the curve is flat, with no significant change in either unavailability value over the range of 9, 10, or 11 years. This was true even for a relay mean time between Failures (MTBF) of 50 years, much lower than MTBF values typically published for these relays. Also, the Markov modeling indicates that both the relay unavailability and abnormal unavailability actually become higher with more frequent testing. This shows that the time spent on these more frequent tests yields no failure discoveries that approach the negative impact of removing the relays from service and running the tests.

The PSMT SDT discussed the practical need for "time-interval extensions" or "grace periods" to allow for scheduling problems that resulted from any number of business contingencies. The time interval discussions also focused on the need to reflect industry norms surrounding Generator outage frequencies. Finally, it was again noted that FERC Order 693 demanded maximum time intervals. "Maximum time intervals" by their very term negates any "time-interval extension" or "grace periods." To recognize the need to follow industry norms on Generator outage frequencies and accommodate a form of time-interval extension, while still following FERC Order 693, the Standard Drafting Team arrived at a six-year interval for the electromechanical relay, instead of the five-year interval arrived at by the SPCTF. The PSMT SDT has followed the FERC directive for a *maximum* time interval and has determined that no extensions will be allowed. Six years has been set for the maximum time interval between manual maintenance activities. This maximum time interval also works well for maintenance cycles that have been in use in generator plants for decades.

For monitored relays, the PSMT SDT notes that the SPCTF called for 10 years as the interval between maintenance activities. This 10-year interval was chosen, even though there was "…no significant change in unavailability value over the range of 9, 10, or 11 years. This was true even for a relay Mean Time between Failures (MTBF) of 50 years…" The Standard Drafting Team again sought to align maintenance activities with known successful practices and outage schedules. The Standard does not allow extensions on any component of the Protection System; thus, the maximum allowed interval for these components has been set to 12 years. Twelve years also fits well into the traditional maintenance cycles of both substations and generator plants.

Also of note is the Table's use of the term "Calendar" in the column for "Maximum Maintenance Interval." The PSMT SDT deemed it necessary to include the term "Calendar" to facilitate annual maintenance planning, scheduling and implementation. This need is the result of known occurrences of system requirements that could cause maintenance schedules to be missed by a few days or weeks. The PSMT SDT chose the term "Calendar" to preclude the need to have schedules be met to the day. An electromechanical protective relay that is maintained in year number one need not be revisited until six years later (year number seven). For example, a relay was maintained April 10, 2008; maintenance would need to be completed no later than December 31, 2014.

Though not a requirement of this standard, to stay in line with many Compliance Enforcement Agencies audit processes an entity should define, within their own PSMP, the entity’s use of terms like annual, calendar year, etc. Then, once this is within the PSMP, the entity should abide by their chosen language.

9. Performance-Based Maintenance Process

In lieu of using the Table 1 intervals, a Performance-Based Maintenance process may be used to establish maintenance intervals (*PRC-005 Attachment A Criteria for a Performance-Based Protection System Maintenance Program*). A Performance-Based Maintenance process may justify longer maintenance intervals, or require shorter intervals relative to Table 1. In order to use a Performance-Based Maintenance process, the documented maintenance program must include records of repairs, adjustments, and corrections to covered Protection Systems in order to provide historical justification for intervals, other than those established in Table 1. Furthermore, the asset owner must regularly analyze these records of corrective actions to develop a ranking of causes. Recurrent problems are to be highlighted, and remedial action plans are to be documented to mitigate or eliminate recurrent problems.

Entities with Performance-Based Maintenance track performance of Protection Systems, demonstrate how they analyze findings of performance failures and aberrations, and implement continuous improvement actions. Since no maintenance program can ever guarantee that no malfunction can possibly occur, documentation of a Performance-Based Maintenance program would serve the utility well in explaining to regulators and the public a Misoperation leading to a major System outage event.

A Performance-Based Maintenance program requires auditing processes like those included in widely used industrial quality systems (such as ***ISO 9001-2000, Quality Management Systems — Requirements;*** or applicable parts of the NIST Baldridge National Quality Program). The audits periodically evaluate:

- The completeness of the documented maintenance process
- Organizational knowledge of and adherence to the process
- Performance metrics and documentation of results
- Remediation of issues
- Demonstration of continuous improvement.

In order to opt into a Performance-Based Maintenance (PBM) program, the asset owner must first sort the various Components into population segments. Any population segment must be comprised of at least 60 individual units; if any asset owner opts for PBM, but does not own 60 units to comprise a population, then that asset owner may combine data from other asset owners until the needed 60 units is aggregated. Each population segment must be composed of a grouping of Components of a consistent design standard or particular model or type from a single manufacturer and subjected to similar environmental factors. For example: One segment cannot be comprised of both GE & Westinghouse electro-mechanical lock-out relays; likewise, one segment cannot be comprised of 60 GE lock-out relays, 30 of which are in a dirty environment, and the remaining 30 from a clean environment. This PBM process cannot be applied to batteries, but can be applied to all other Components, including (but not limited to) specific battery chargers, instrument transformers, trip coils and/or control circuitry (etc.).

9.1 Minimum Sample Size

Large Sample Size

An assumption that needs to be made when choosing a sample size is "the sampling distribution of the sample mean can be approximated by a normal probability distribution." The Central Limit Theorem states: "In selecting simple random samples of size *n* from a population, the sampling distribution of the sample mean *x* can be approximated by a normal probability distribution as the sample size becomes large." (Essentials of Statistics for Business and Economics, Anderson, Sweeney, Williams, 2003.)

To use the Central Limit Theorem in statistics, the population size should be large. The references below are supplied to help define what is large.

> "… whenever we are using a large simple random sample (rule of thumb: n>=30), the central limit theorem enables us to conclude that the sampling distribution of the sample mean can be approximated by a normal distribution." (Essentials of Statistics for Business and Economics, Anderson, Sweeney, Williams, 2003.)
>
> "If samples of size n, when n>=30, are drawn from any population with a mean *u* and a standard deviation σ, the sampling distribution of sample means approximates a normal distribution. The greater the sample size, the better the approximation." (Elementary Statistics - Picturing the World, Larson, Farber, 2003.)
>
> "The sample size is large (generally n>=30)… (Introduction to Statistics and Data Analysis - Second Edition, Peck, Olson, Devore, 2005.)
>
> "… the normal is often used as an approximation to the *t* distribution in a test of a null hypothesis about the mean of a normally distributed population when the population variance is estimated from a relatively large sample. A sample size exceeding 30 is often given as a minimal size in this connection." (Statistical Analysis for Business Decisions, Peters, Summers, 1968.)

Error of Distribution Formula

Beyond the large sample size discussion above, a sample size requirement can be estimated using the bound on the Error of Distribution Formula when the expected result is of a "Pass/Fail" format and will be between 0 and 1.0.

The Error of Distribution Formula is:

$$B = z\sqrt{\frac{\pi(1-\pi)}{n}}$$

Where:

B = bound on the error of distribution (allowable error)

z = standard error

π = expected failure rate

n = sample size required

Solving for n provides:

$$n = \pi(1-\pi)\left(\frac{z}{B}\right)^2$$

Minimum Population Size to use Performance-Based Program

One entity's population of components should be large enough to represent a sizeable sample of a vendor's overall population of manufactured devices. For this reason, the following assumptions are made:

B = 5%

z = 1.96 (This equates to a 95% confidence level)

π = 4%

Using the equation above, n=59.0.

Minimum Sample Size to evaluate Performance-Based Program

The number of components that should be included in a sample size for evaluation of the appropriate testing interval can be smaller because a lower confidence level is acceptable since the sample testing is repeated or updated annually. For this reason, the following assumptions are made:

B = 5%

z = 1.44 (85% confidence level)

π = 4%

Using the equation above, n=31.8.

Recommendation

Based on the above discussion, a sample size should be at least 30 to allow use of the equation mentioned. Using this and the results of the equation, the following numbers are recommended (and required within the standard):

Minimum Population Size to use Performance-Based Maintenance Program = 60

Minimum Sample Size to evaluate Performance-Based Program = 30.

Once the population segment is defined, then maintenance must begin within the intervals as outlined for the device described in the Tables 1-1 through 1-5. Time intervals can be lengthened provided the last year's worth of components tested (or the last 30 units maintained, whichever is more) had fewer than 4% Countable Events. It is notable that 4% is specifically chosen because an entity with a small population (30 units) would have to adjust its time intervals between maintenance if more than one Countable Event was found to have occurred during the last analysis period. A smaller percentage would require that entity to adjust the time interval between maintenance activities if even one unit is found out of tolerance or causes a Misoperation.

The minimum number of units that can be tested in any given year is 5% of the population. Note that this 5% threshold sets a practical limitation on total length of time between intervals at 20 years.

If at any time the number of Countable Events equals or exceeds 4% of the last year's tested components (or the last 30 units maintained, whichever is more), then the time period between manual maintenance activities must be decreased. There is a time limit on reaching the decreased time at which the Countable Events is less than 4%; this must be attained within three years.

Performance-Based Program Evaluation Example

The 4% performance target was derived as a protection system performance target and was selected based on the drafting team's experience and studies performed by several utilities. This is not derived from the performance of discrete devices. Microprocessor relays and electromechanical relays have different performance levels. It is not appropriate to compare these performance levels to each other. The performance of the segment should be compared to the 4% performance criteria.

In consideration of the use of Performance Based Maintenance (PBM), the user should consider the effects of extended testing intervals and the established 4% failure rate. In the table shown below, the segment is 1000 units. As the testing interval (in years) increases, the number of units tested each year decreases. The number of countable events allowed is 4% of the tested units. Countable events are the failure of a Component requiring repair or replacement, any corrective actions performed during the maintenance test on the units within the testing segment (units per year), or any misoperation attributable to hardware failure or calibration failure found within the entire segment (1000 units) during the testing year.

Example: 1000 units in the segment with a testing interval of 8 years: The number of units tested each year will be 125 units. The total allowable countable events equals: 125 X .04 = 5. This number includes failure of a Component requiring repair or replacement, corrective issues found during testing, and the total number of misoperations (attributable to hardware or calibration failure within the testing year) associated with the entire segment of 1000 units.

Example: 1000 units in the segment with a testing interval of 16 years: The number of units tested each year will be 63 units. The total allowable countable events equals: 63 X .04 = 2.5.

As shown in the above examples, doubling the testing interval reduces the number of allowable events by half.

Total number of units in the segment	1000
Failure rate	4.00%

Testing Intervals (Years)	Units Per Year	Acceptable Number of Countable Events per year	Yearly Failure Rate Based on 1000 Units in Segment
1	1000.00	40.00	4.00%
2	500.00	20.00	2.00%
4	250.00	10.00	1.00%
6	166.67	6.67	0.67%
8	125.00	5.00	0.50%
10	100.00	4.00	0.40%
12	83.33	3.33	0.33%
14	71.43	2.86	0.29%
16	62.50	2.50	0.25%
18	55.56	2.22	0.22%
20	50.00	2.00	0.20%

Using the prior year's data, determine the maximum allowable maintenance interval for each Segment such that the Segment experiences Countable Events on no more than 4% of the Components within the Segment, for the greater of either the last 30 Components maintained or all Components maintained in the previous year.

Segment – Components of a consistent design standard, or a particular model or type from a single manufacturer that typically share other common elements. Consistent performance is expected across the entire population of a Segment. A Segment must contain at least sixty (60) individual Components.

Countable Event – A failure of a Component requiring repair or replacement, any condition discovered during the maintenance activities in Tables 1-1 through 1-5, Table 3, Table 4-1 through Table 4-2, and Table 5, which requires corrective action or a Protection System Misoperation attributed to hardware failure or calibration failure. Misoperations due to product design errors, software errors, relay settings different from specified settings, Protection System Component, Automatic Reclosing, or Sudden Pressure Relaying configuration or application errors are not included in Countable Events.

9.2 Frequently Asked Questions:

I'm a small entity and cannot aggregate a population of Protection System components to establish a segment required for a Performance-Based Protection System Maintenance Program. How can I utilize that opportunity?

Multiple asset owning entities may aggregate their individually owned populations of individual Protection System components to create a segment that crosses ownership boundaries. All entities participating in a joint program should have a single documented joint management

process, with consistent Protection System Maintenance Programs (practices, maintenance intervals and criteria), for which the multiple owners are individually responsible with respect to the requirements of the Standard. The requirements established for Performance-Based Maintenance must be met for the overall aggregated program on an ongoing basis.

The aggregated population should reflect all factors that affect consistent performance across the population, including any relevant environmental factors such as geography, power-plant vs. substation, and weather conditions.

Can an owner go straight to a Performance-Based Maintenance program schedule, if they have previously gathered records?

Yes. An owner can go to a Performance-Based Maintenance program immediately. The owner will need to comply with the requirements of a Performance-Based Maintenance program as listed in the Standard. Gaps in the data collected will not be allowed; therefore, if an owner finds that a gap exists such that they cannot prove that they have collected the data as required for a Performance-Based Maintenance program then they will need to wait until they can prove compliance.

When establishing a Performance-Based Maintenance program, can I use test data from the device manufacturer, or industry survey results, as results to help establish a basis for my Performance-Based intervals?

No, you must use actual in-service test data for the components in the segment.

What types of Misoperations or events are not considered Countable Events in the Performance-Based Protection System Maintenance (PBM) Program?

Countable Events are intended to address conditions that are attributed to hardware failure or calibration failure; that is, conditions that reflect deteriorating performance of the component. These conditions include any condition where the device previously worked properly, then, due to changes within the device, malfunctioned or degraded to the point that re-calibration (to within the entity's tolerance) was required.
For this purpose of tracking hardware issues, human errors resulting in Protection System Misoperations during system installation or maintenance activities are not considered Countable Events. Examples of excluded human errors include relay setting errors, design errors, wiring errors, inadvertent tripping of devices during testing or installation, and misapplication of Protection System components. Examples of misapplication of Protection System components include wrong CT or PT tap position, protective relay function misapplication, and components not specified correctly for their installation. Obviously, if one is setting up relevant data about hardware failures then human failures should be eliminated from the hardware performance analysis.

One example of human-error is not pertinent data might be in the area of testing "86" lock-out relays (LOR). "Entity A" has two types of LOR's type "X" and type "Y"; they want to move into a performance based maintenance interval. They have 1000 of each type, so the population variables are met. During electrical trip testing of all of their various schemes over the initial six-year interval they find zero type "X" failures, but human error led to tripping a BES Element 100 times; they find 100 type "Y" failures and had an additional 100 human-error caused tripping incidents. In this example the human-error caused Misoperations should not be used to judge the performance of either type of LOR. Analysis of the data might lead "Entity A" to change time intervals. Type "X" LOR can be placed into extended time interval testing because of its low failure rate (zero failures) while Type "Y" would have to be tested more often than every 6 calendar years (100 failures divided by 1000 units exceeds the 4% tolerance level).

Certain types of Protection System component errors that cause Misoperations are not considered Countable Events. Examples of excluded component errors include device malfunctions that are correctable by firmware upgrades and design errors that do not impact protection function.

What are some examples of methods of correcting segment perfomance for Performance-Based Maintenance?

There are a number of methods that may be useful for correcting segment performance for mal-performing segments in a Performance-Based Maintenance system. Some examples are listed below.

- The maximum allowable interval, as established by the Performance-Based Maintenance system, can be decreased. This may, however, be slow to correct the performance of the segment.
- Identifiable sub-groups of components within the established segment, which have been identified to be the mal-performing portion of the segment, can be broken out as an independent segment for target action. Each resulting segment must satisfy the minimum population requirements for a Performance-Based Maintenance program in order to remain within the program.
- Targeted corrective actions can be taken to correct frequently occurring problems. An example would be replacement of capacitors within electromechanical distance relays if bad capacitors were determined to be the cause of the mal-performance.
- components within the mal-performing segment can be replaced with other components (electromechanical distance relays with microprocessor relays, for example) to remove the mal-performing segment.

If I find (and correct) a Unresolved Maintenance Issue as a result of a Misoperation investigation (Re: PRC-004), how does this affect my Performance-Based Maintenance program?

If you perform maintenance on a Protection System component for any reason (including as part of a PRC-004 required Misoperation investigation/corrective action), the actions performed can count as a maintenance activity provided the activities in the relevant Tables have been done, and, if you desire, "reset the clock" on everything you've done. In a Performance-Based Maintenance program, you also need to record the Unresolved Maintenance Issue as a Countable Event within the relevant component group segment and use it in the analysis to determine your correct Performance-Based Maintenance interval for that component group. Note that "resetting the clock" should not be construed as interfering with an entity's routine testing schedule because the "clock-reset" would actually make for a decreased time interval by the time the next routine test schedule comes around.

For example a relay scheme, consisting of four relays, is tested on 1-1-11 and the PSMP has a time interval of 3 calendar years with an allowable extension of 1 calendar year. The relay would be due again for routine testing before the end of the year 2015. This mythical relay scheme has a Misoperation on 6-1-12 that points to one of the four relays as bad. Investigation proves a bad relay and a new one is tested and installed in place of the original. This replacement relay actually could be retested before the end of the year 2016 (clock-reset) and not be out of compliance. This requires tracking maintenance by individual relays and is allowed. However, many companies schedule maintenance in other ways like by substation or by circuit breaker or by relay scheme. By these methods of tracking maintenance that "replaced relay" will be retested before the end of the year 2015. This is also acceptable. In no case was a particular relay tested beyond the PSMP of four years max, nor was the 6 year max of the Standard exceeded. The entity can reset the clock if they desire or the entity can continue with original schedules and, in effect, test even more frequently.

Why are batteries excluded from PBM? What about exclusion of batteries from condition based maintenance?

Batteries are the only element of a Protection System that is a perishable item with a shelf life. As a perishable item batteries require not only a constant float charge to maintain their freshness (charge), but periodic inspection to determine if there are problems associated with their aging process and testing to see if they are maintaining a charge or can still deliver their rated output as required.

Besides being perishable, a second unique feature of a battery that is unlike any other Protection System element is that a battery uses chemicals, metal alloys, plastics, welds, and bonds that must interact with each other to produce the constant dc source required for Protection Systems, undisturbed by ac system Disturbances.

No type of battery manufactured today for Protection System application is free from problems that can only be detected over time by inspection and test. These problems can arise from variances in the manufacturing process, chemicals and alloys used in the construction of the individual cells, quality of welds and bonds to connect the components, the plastics used to make batteries and the cell forming process for the individual battery cells.

Other problems that require periodic inspection and testing can result from transportation from the factory to the job site, length of time before a charge is put on the battery, the method of installation, the voltage level and duration of equalize charges, the float voltage level used, and the environment that the battery is installed in.

All of the above mentioned factors and several more not discussed here are beyond the control of the Functional Entities that want to use a Performance-Based Protection System Maintenance (PBM) program. These inherent variances in the aging process of a battery cell make establishment of a designated segment based on manufacturer and type of battery impossible.

The whole point of PBM is that if all variables are isolated then common aging and performance criteria would be the same. However, there are too many variables in the electrochemical process to completely isolate all of the performance-changing criteria.

Similarly, Functional Entities that want to establish a condition-based maintenance program using the highest levels of monitoring, resulting in the least amount of hands-on maintenance activity, cannot completely eliminate some periodic maintenance of the battery used in a station dc supply. Inspection of the battery is required on a Maximum Maintenance Interval listed in the tables due to the aging processes of station batteries. However, higher degrees of

monitoring of a battery can eliminate the requirement for some periodic testing and some inspections (see Table 1-4).

Please provide an example of the calculations involved in extending maintenance time intervals using PBM.

Entity has 1000 GE-HEA lock-out relays; this is greater than the minimum sample requirement of 60. They start out testing all of the relays within the prescribed Table requirements (6 year max) by testing the relays every 5 years. The entity's plan is to test 200 units per year; this is greater than the minimum sample size requirement of 30. For the sake of example only the following will show 6 failures per year, reality may well have different numbers of failures every year. PBM requires annual assessment of failures found per units tested. After the first year of tests the entity finds 6 failures in the 200 units tested. 6/200= 3% failure rate. This entity is now allowed to extend the maintenance interval if they choose. The entity chooses to extend the maintenance interval of this population segment out to 10 years. This represents a rate of 100 units tested per year; entity selects 100 units to be tested in the following year. After that year of testing these 100 units the entity again finds 6 failed units. 6/100= 6% failures. This entity has now exceeded the acceptable failure rate for these devices and must accelerate testing of all of the units at a higher rate such that the failure rate is found to be less than 4% per year; the entity has three years to get this failure rate down to 4% or less (per year). In response to the 6% failure rate, the entity decreases the testing interval to 8 years. This means that they will now test 125 units per year (1000/8). The entity has just two years left to get the test rate corrected.

After a year, they again find six failures out of the 125 units tested. 6/125= 5% failures. In response to the 5% failure rate, the entity decreases the testing interval to seven years. This means that they will now test 143 units per year (1000/7). The entity has just one year left to get the test rate corrected. After a year, they again find six failures out of the 143 units tested. 6/143= 4.2% failures.

(Note that the entity has tried five years and they were under the 4% limit and they tried seven years and they were over the 4% limit. They must be back at 4% failures or less in the next year so they might simply elect to go back to five years.)

Instead, in response to the 5% failure rate, the entity decreases the testing interval to six years. This means that they will now test 167 units per year (1000/6). After a year, they again find six failures out of the 167 units tested. 6/167= 3.6% failures. Entity found that they could maintain the failure rate at no more than 4% failures by maintaining the testing interval at six years or less. Entity chose six-year interval and effectively extended their TBM (five years) program by 20%.

A note of practicality is that an entity will probably be in better shape to lengthen the intervals between tests if the failure rate is less than 2%. But the requirements allow for annual adjustments, if the entity desires. As a matter of maintenance management, an ever-changing test rate (units tested/year) may be un-workable.

Note that the "5% of components" requirement effectively sets a practical limit of 20 year maximum PBM interval. Also of note is the "3 years" requirement; an entity might arbitrarily extend time intervals from six years to 20 years. In the event that an entity finds a failure rate greater than 4%, then the test rate must be accelerated such that within three years the failure rate must be brought back down to 4% or less.

Here is a table that demonstrates the values discussed:

Year #	Total Population (P)	Test Interval (I)	Units to be Tested (U= P/I)	# of Failures Found (F)	Failure Rate (=F/U)	Decision to Change Interval Yes or No	Interval Chosen
1	1000	5 yrs	200	6	3%	Yes	10 yrs
2	1000	10 yrs	100	6	6%	Yes	8 yrs
3	1000	8 yrs	125	6	5%	Yes	7 yrs
4	1000	7 yrs	143	6	4.2%	Yes	6 yrs
5	1000	6 yrs	167	6	3.6%	No	6 yrs

Please provide an example of the calculations involved in extending maintenance time intervals using PBM for control circuitry.

Note that the following example captures "Control Circuitry" as all of the trip paths associated with a particular trip coil of a circuit breaker. An entity is not restricted to this method of counting control circuits. Perhaps another method an entity would prefer would be to simply track every individual (parallel) trip path. Or perhaps another method would be to track all of the trip outputs from a specific (set) of relays protecting a specific element.

The designation of what constitutes a control circuit component is very dependent upon how an entity performs and tracks the testing of the control circuitry. Some entities test their control circuits on a breaker basis whereas others test their circuitry on a local zone of protection basis. Thus, entities are allowed the latitude to designate their own definitions of control circuit components. Another example of where the entity has some discretion on determining what constitutes a single component is the voltage and current sensing devices, where the entity may choose either to designate a full three-phase set of such devices or a single device as a single component.

And in Attachment A (PBM) the definition of Segment:

Segment –*Components of a consistent design standard, or a particular model or type from a single manufacturer that typically share other common elements. Consistent performance is expected across the entire population of a segment. A segment must contain at least sixty (60) individual components.*

Example:

Entity has 1,000 circuit breakers, all of which have two trip coils, for a total of 2,000 trip coils; if all circuitry was designed and built with a consistent (internal entity) standard, then this is greater than the minimum sample requirement of 60.

For the sake of further example, the following facts are given:

Half of all relay panels (500) were built 40 years ago by an outside contractor, consisted of asbestos wrapped 600V-insulation panel wiring, and the cables exiting the control house are THHN pulled in conduit direct to exactly half of all of the various circuit breakers. All of the relay panels and cable pulls were built with consistent standards and consistent performance standard expectations within the segment (which is greater than 60). Each relay panel has redundant microprocessor (MPC) relays (retrofitted); each MPC relay supplies an individual trip output to each of the two trip coils of the assigned circuit breaker.

Approximately 35 years ago, the entity developed their own internal construction crew and now builds all of their own relay panels from parts supplied from vendors that meet the entity's specifications, including SIS 600V insulation wiring and copper-sheathed cabling within the direct conduits to circuit breakers. The construction crew uses consistent standards in the construction. This newer segment of their control circuitry population is different than the original segment, consistent (standards, construction and performance expectations) within the new segment and constitutes the remainder of the entity's population (another 500 panels and the cabling to the remaining 500 circuit breakers). Each relay panel has redundant microprocessor (MPC) relays; each MPC relay supplies an individual trip output to each of the two trip coils of the assigned circuit breaker. Every trip path in this newer segment has a device that monitors the voltage directly across the trip contacts of the MPC relays and alarms via RTU and SCADA to the operations control room. This monitoring device, when not in alarm, demonstrates continuity all the way through the trip coil, cabling and wiring back to the trip contacts of the MPC relay.

The entity is tracking 2,000 trip coils (each consisting of multiple trip paths) in each of these two segments. But half of all of the trip paths are monitored; therefore, the trip paths are continuously tested and the circuit will alarm when there is a failure. These alarms have to be verified every 12 years for correct operation.

The entity now has 1,000 trip coils (and associated trip paths) remaining that they have elected to count as control circuits. The entity has instituted a process that requires the verification of every trip path to each trip coil (one unit), including the electrical activation of the trip coil. (The entity notes that the trip coils will have to be tripped electrically more often than the trip path verification, and is taking care of this activity through other documentation of Real-time Fault operations.)

They start out testing all of the trip coil circuits within the prescribed Table requirements (12-year max) by testing the trip circuits every 10 years. The entity's plan is to test 100 units per year; this is greater than the minimum sample size requirement of 30. For the sake of example only, the following will show three failures per year; reality may well have different numbers of failures every year. PBM requires annual assessment of failures found per units tested. After the first year of tests, the entity finds three failures in the 100 units tested. 3/100= 3% failure rate.

This entity is now allowed to extend the maintenance interval, if they choose. The entity chooses to extend the maintenance interval of this population segment out to 20 years. This represents a rate of 50 units tested per year; entity selects 50 units to be tested in the following year. After that year of testing these 50 units, the entity again finds three failed units. 3/50= 6% failures.

This entity has now exceeded the acceptable failure rate for these devices and must accelerate testing of all of the units at a higher rate, such that the failure rate is found to be less than 4% per year; the entity has three years to get this failure rate down to 4% or less (per year).

In response to the 6% failure rate, the entity decreases the testing interval to 16 years. This means that they will now test 63 units per year (1000/16). The entity has just two years left to get the test rate corrected. After a year, they again find three failures out of the 63 units tested. 3/63= 4.76% failures.

In response to the >4% failure rate, the entity decreases the testing interval to 14 years. This means that they will now test 72 units per year (1000/14). The entity has just one year left to get the test rate corrected. After a year, they again find three failures out of the 72 units tested. 3/72= 4.2% failures.

(Note that the entity has tried 10 years, and they were under the 4% limit; and they tried 14 years, and they were over the 4% limit. They must be back at 4% failures or less in the next year, so they might simply elect to go back to 10 years.)

Instead, in response to the 4.2% failure rate, the entity decreases the testing interval to 12 years. This means that they will now test 84 units per year (1000/12). After a year, they again find three failures out of the 84 units tested. 3/84= 3.6% failures.

Entity found that they could maintain the failure rate at no more than 4% failures by maintaining the testing interval at 12 years or less. Entity chose 12-year interval, and effectively extended their TBM (10 years) program by 20%.

A note of practicality is that an entity will probably be in better shape to lengthen the intervals between tests if the failure rate is less than 2%. But the requirements allow for annual adjustments if the entity desires. As a matter of maintenance management, an ever-changing test rate (units tested / year) may be un-workable.

Note that the "5% of components" requirement effectively sets a practical limit of 20-year maximum PBM interval. Also of note is the "3 years" requirement; an entity might arbitrarily extend time intervals from six years to 20 years. In the event that an entity finds a failure rate greater than 4%, then the test rate must be accelerated such that within three years the failure rate must be brought back down to 4% or less.

Here is a table that demonstrates the values discussed:

Year #	Total Population (P)	Test Interval (I)	Units to be Tested (U= P/I)	# of Failures Found (F)	Failure Rate (=F/U)	Decision to Change Interval Yes or No	Interval Chosen
1	1000	10 yrs	100	3	3%	Yes	20 yrs
2	1000	20 yrs	50	3	6%	Yes	16yrs
3	1000	16 yrs	63	3	4.8%	Yes	14 yrs
4	1000	14 yrs	72	3	4.2%	Yes	12 yrs
5	1000	12 yrs	84	3	3.6%	No	12 yrs

Please provide an example of the calculations involved in extending maintenance time intervals using PBM for voltage and current sensing devices.

Note that the following example captures "voltage and current inputs to the protective relays" as all of the various current transformer and potential transformer signals associated with a particular set of relays used for protection of a specific Element. This entity calls this set of protective relays a "Relay Scheme." Thus, this entity chooses to count PT and CT signals as a group instead of individually tracking maintenance activities to specific bushing CT's or specific PT's. An entity is not restricted to this method of counting voltage and current devices, signals and paths. Perhaps another method an entity would prefer would be to simply track every individual PT and CT. Note that a generation maintenance group may well select the latter because they may elect to perform routine off-line tests during generator outages, whereas a transmission maintenance group might create a process that utilizes Real-time system values measured at the relays.

The designation of what constitutes a control circuit component is very dependent upon how an entity performs and tracks the testing of the control circuitry. Some entities test their control circuits on a breaker basis whereas others test their circuitry on a local zone of protection basis. Thus, entities are allowed the latitude to designate their own definitions of control circuit components. Another example of where the entity has some discretion on determining what constitutes a single component is the voltage and current sensing devices, where the entity may choose either to designate a full three-phase set of such devices or a single device as a single component.

And in Attachment A (PBM) the definition of Segment:

Segment –*Components of a consistent design standard, or a particular model or type from a single manufacturer that typically share other common elements. Consistent performance is expected across the entire population of a segment. A segment must contain at least sixty (60) individual components.*

Example:

Entity has 2000 "Relay Schemes," all of which have three current signals supplied from bushing CTs, and three voltage signals supplied from substation bus PT's. All cabling and circuitry was designed and built with a consistent (internal entity) standard, and this population is greater than the minimum sample requirement of 60.

For the sake of further example the following facts are given:

Half of all relay schemes (1,000) are supplied with current signals from ANSI STD C800 bushing CTs and voltage signals from PTs built by ACME Electric MFR CO. All of the relay panels and cable pulls were built with consistent standards, and consistent performance standard expectations exist for the consistent wiring, cabling and instrument transformers within the segment (which is greater than 60).

The other half of the entity's relay schemes have MPC relays with additional monitoring built-in that compare DNP values of voltages and currents (or Watts and VARs), as interpreted by the MPC relays and alarm for an entity-accepted tolerance level of accuracy. This newer segment of their "Voltage and Current Sensing" population is different than the original segment, consistent (standards, construction and performance expectations) within the new segment and constitutes the remainder of the entity's population.

The entity is tracking many thousands of voltage and current signals within 2,000 relay schemes (each consisting of multiple voltage and current signals) in each of these two segments. But half of all of the relay schemes voltage and current signals are monitored; therefore, the voltage and current signals are continuously tested and the circuit will alarm when there is a failure; these alarms have to be verified every 12 years for correct operation.

The entity now has 1,000 relay schemes worth of voltage and current signals remaining that they have elected to count within their relay schemes designation. The entity has instituted a process that requires the verification of these voltage and current signals within each relay scheme (one unit).

(Please note - a problem discovered with a current or voltage signal found at the relay could be caused by anything from the relay, all the way to the signal source itself. Having many sources of problems can easily increase failure rates beyond the rate of failures of just one item (for example just PTs). It is the intent of the SDT to minimize failure rates of all of the equipment to an acceptable level; thus, any failure of any item that gets the signal from source to relay is counted. It is for this reason that the SDT chose to set the boundary at the ability of the signal to be delivered all the way to the relay.

The entity will start out measuring all of the relay scheme voltage and currents at the individual relays within the prescribed Table requirements (12 year max) by measuring the voltage and current values every 10 years. The entity's plan is to test 100 units per year; this is greater than the minimum sample size requirement of 30. For the sake of example only, the following will show three failures per year; reality may well have different numbers of failures every year. PBM requires annual assessment of failures found per units tested. After the first year of tests, the entity finds three failures in the 100 units tested. 3/100= 3% failure rate.

This entity is now allowed to extend the maintenance interval, if they choose. The entity chooses to extend the maintenance interval of this population segment out to 20 years. This represents a rate of 50 units tested per year; entity selects 50 units to be tested in the following year. After that year of testing these 50 units, the entity again finds three failed units. 3/50= 6% failures.

This entity has now exceeded the acceptable failure rate for these devices and must accelerate testing of all of the units at a higher rate, such that the failure rate is found to be less than 4% per year; the entity has three years to get this failure rate down to 4% or less (per year).

In response to the 6% failure rate, the entity decreases the testing interval to 16 years. This means that they will now test 63 units per year (1000/16). The entity has just two years left to get the test rate corrected. After a year, they again find three failures out of the 63 units tested. 3/63= 4.76% failures.

In response to the >4%failure rate, the entity decreases the testing interval to 14 years. This means that they will now test 72 units per year (1000/14). The entity has just one year left to get the test rate corrected. After a year, they again find three failures out of the 72 units tested. 3/72= 4.2% failures.

(Note that the entity has tried 10 years, and they were under the 4% limit; and they tried 14 years, and they were over the 4% limit. They must be back at 4% failures or less in the next year, so they might simply elect to go back to 10 years.)

Instead, in response to the 4.2% failure rate, the entity decreases the testing interval to 12 years. This means that they will now test 84 units per year (1,000/12). After a year, they again find three failures out of the 84 units tested. 3/84= 3.6% failures.

Entity found that they could maintain the failure rate at no more than 4% failures by maintaining the testing interval at 12 years or less. Entity chose 12-year interval and effectively extended their TBM (10 years) program by 20%.

A note of practicality is that an entity will probably be in better shape to lengthen the intervals between tests if the failure rate is less than 2%. But the requirements allow for annual adjustments, if the entity desires. As a matter of maintenance management, an ever-changing test rate (units tested/year) may be un-workable.

Note that the "5% of components" requirement effectively sets a practical limit of 20-year maximum PBM interval. Also of note is the "3 years" requirement; an entity might arbitrarily extend time intervals from six years to 20 years. In the event that an entity finds a failure rate greater than 4%, then the test rate must be accelerated such that within three years the failure rate must be brought back down to 4% or less.

Here is a table that demonstrates the values discussed:

Year #	Total Population (P)	Test Interval (I)	Units to be Tested (U= P/I)	# of Failures Found (F)	Failure Rate (=F/U)	Decision to Change Interval Yes or No	Interval Chose
1	1000	10 yrs	100	3	3%	Yes	20 yrs
2	1000	20 yrs	50	3	6%	Yes	16yrs
3	1000	16 yrs	63	3	4.8%	Yes	14 yrs
4	1000	14 yrs	72	3	4.2%	Yes	12 yrs
5	1000	12 yrs	84	3	3.6%	No	12 yrs

10. Overlapping the Verification of Sections of the Protection System

Tables 1-1 through 1-5 require that every Protection System component be periodically verified. One approach, but not the only method, is to test the entire protection scheme as a unit, from the secondary windings of voltage and current sources to breaker tripping. For practical ongoing verification, sections of the Protection System may be tested or monitored individually. The boundaries of the verified sections must overlap to ensure that there are no gaps in the verification. See Appendix A of this Supplementary Reference for additional discussion on this topic.

All of the methodologies expressed within this report may be combined by an entity, as appropriate, to establish and operate a maintenance program. For example, a Protection System may be divided into multiple overlapping sections with a different maintenance methodology for each section:

- Time-based maintenance with appropriate maximum verification intervals for categories of equipment, as given in the Tables 1-1 through 1-5;
- Monitoring as described in Tables 1-1 through 1-5;
- A Performance-Based Maintenance program as described in Section 9 above, or Attachment A of the standard;
- Opportunistic verification using analysis of Fault records, as described in Section 11

10.1 Frequently Asked Questions:

My system has alarms that are gathered once daily through an auto-polling system; this is not really a conventional SCADA system but does it meet the Table 1 requirements for inclusion as a monitored system?

Yes, provided the auto-polling that gathers the alarms reports those alarms to a location where the action can be initiated to correct the Unresolved Maintenance Issue. This location does not have to be the location of the engineer or the technician that will eventually repair the problem, but rather a location where the action can be initiated.

11. Monitoring by Analysis of Fault Records

Many users of microprocessor relays retrieve Fault event records and oscillographic records by data communications after a Fault. They analyze the data closely if there has been an apparent Misoperation, as NERC standards require. Some advanced users have commissioned automatic Fault record processing systems that gather and archive the data. They search for evidence of component failures or setting problems hidden behind an operation whose overall outcome seems to be correct. The relay data may be augmented with independently captured Digital Fault Recorder (DFR) data retrieved for the same event.

Fault data analysis comprises a legitimate CBM program that is capable of reducing the need for a manual time-interval based check on Protection Systems whose operations are analyzed. Even electromechanical Protection Systems instrumented with DFR channels may achieve some CBM benefit. The completeness of the verification then depends on the number and variety of Faults in the vicinity of the relay that produce relay response records and the specific data captured.

A typical Fault record will verify particular parts of certain Protection Systems in the vicinity of the Fault. For a given Protection System installation, it may or may not be possible to gather within a reasonable amount of time an ensemble of internal and external Fault records that completely verify the Protection System.

For example, Fault records may verify that the particular relays that tripped are able to trip via the control circuit path that was specifically used to clear that Fault. A relay or DFR record may indicate correct operation of the protection communications channel. Furthermore, other nearby Protection Systems may verify that they restrain from tripping for a Fault just outside their respective zones of protection. The ensemble of internal Fault and nearby external Fault event data can verify major portions of the Protection System, and reset the time clock for the Table 1 testing intervals for the verified components only.

What can be shown from the records of one operation is very specific and limited. In a panel with multiple relays, only the specific relay(s) whose operation can be observed without ambiguity should be used. Be careful about using Fault response data to verify that settings or calibration are correct. Unless records have been captured for multiple Faults close to either side of a setting boundary, setting or calibration could still be incorrect.

PMU data, much like DME data, can be utilized to prove various components of the Protection System. Obviously, care must be taken to attribute proof only to the parts of a Protection System that can actually be proven using the PMU or DME data.

If Fault record data is used to show that portions or all of a Protection System have been verified to meet Table 1 requirements, the owner must retain the Fault records used, and the maintenance-related conclusions drawn from this data and used to defer Table 1 tests, for at least the retention time interval given in Section 8.2.

11.1 Frequently Asked Questions:

I use my protective relays for Fault and Disturbance recording, collecting oscillographic records and event records via communications for Fault analysis to meet NERC and DME requirements. What are the maintenance requirements for the relays?

For relays used only as Disturbance Monitoring Equipment, NERC Standard PRC-018-1 R3 & R6 states the maintenance requirements and is being addressed by a standards activity that is revising PRC-002-1 and PRC-018-1. For protective relays "that are designed to provide protection for the BES," this standard applies, even if they also perform DME functions.

12. Importance of Relay Settings in Maintenance Programs

In manual testing programs, many utilities depend on pickup value or zone boundary tests to show that the relays have correct settings and calibration. Microprocessor relays, by contrast, provide the means for continuously monitoring measurement accuracy. Furthermore, the relay digitizes inputs from one set of signals to perform all measurement functions in a single self-monitoring microprocessor system. These relays do not require testing or calibration of each setting.

However, incorrect settings may be a bigger risk with microprocessor relays than with older relays. Some microprocessor relays have hundreds or thousands of settings, many of which are critical to Protection System performance.

Monitoring does not check measuring element settings. Analysis of Fault records may or may not reveal setting problems. To minimize risk of setting errors after commissioning, the user should enforce strict settings data base management, with reconfirmation (manual or automatic) that the installed settings are correct whenever maintenance activity might have changed them; for background and guidance, see [5] in References.

Table 1 requires that settings must be verified to be as specified. The reason for this requirement is simple: With legacy relays (non-microprocessor protective relays), it is necessary to know the value of the intended setting in order to test, adjust and calibrate the relay. Proving that the relay works per specified setting was the de facto procedure. However, with the advanced microprocessor relays, it is possible to change relay settings for the purpose of verifying specific functions and then neglect to return the settings to the specified values. While there is no specific requirement to maintain a settings management process, there remains a need to verify that the settings left in the relay are the intended, specified settings. This need may manifest itself after any of the following:

- One or more settings are changed for any reason.
- A relay fails and is repaired or replaced with another unit.
- A relay is upgraded with a new firmware version.

12.1 Frequently Asked Questions:

How do I approach testing when I have to upgrade firmware of a microprocessor relay?

The entity should ensure that the relay continues to function properly after implementation of firmware changes. Some entities may have a R&D department that might routinely run acceptance tests on devices with firmware upgrades before allowing the upgrade to be installed. Other entities may rely upon the vigorous testing of the firmware OEM. An entity has the latitude to install devices and/or programming that they believe will perform to their satisfaction. If an entity should choose to perform the maintenance activities specified in the Tables following a firmware upgrade, then they may, if they choose, reset the time clock on that set of maintenance activities so that they would not have to repeat the maintenance on its regularly scheduled cycle. (However, for simplicity in maintenance schedules, some entities may choose to not reset this time clock; it is merely a suggested option.)

If I upgrade my old relays, then do I have to maintain my previous equipment maintenance documentation?

If an equipment item is repaired or replaced, then the entity can restart the maintenance-activity-time-interval-clock, if desired; however, the replacement of equipment does not remove any documentation requirements. The requirements in the standard are intended to ensure that an entity has a maintenance plan, and that the entity adheres to minimum activities and maximum time intervals. The documentation requirements are intended to help an entity demonstrate compliance. For example, saving the dates and records of the last two maintenance activities is intended to demonstrate compliance with the interval. Therefore, if you upgrade or replace equipment, then you still must maintain the documentation for the previous equipment, thus demonstrating compliance with the time interval requirement prior to the replacement action.

We have a number of installations where we have changed our Protection System components. Some of the changes were upgrades, but others were simply system rating changes that merely required taking relays "out-of-service". What are our responsibilities when it comes to "out-of-service" devices?

Assuming that your system up-rates, upgrades and overall changes meet any and all other requirements and standards, then the requirements of PRC-005-4~~X~~ are simple – if the Protection System component performs a Protection System function, then it must be maintained. If the component no longer performs Protection System functions, then it does not require maintenance activities under the Tables of PRC-005-4~~X~~. While many entities might physically remove a component that is no longer needed, there is no requirement in PRC-005-4~~X~~ to remove such component(s). Obviously, prudence would dictate that an "out-of-service" device is truly made inactive. There are no record requirements listed in PRC-005-4~~X~~ for Protection System components not used.

While performing relay testing of a protective device on our Bulk Electric System, it was discovered that the protective device being tested was either broken or out of calibration. Does this satisfy the relay testing requirement, even though the protective device tested bad, and may be unable to be placed back into service?

Yes, PRC-005-4~~X~~ requires entities to perform relay testing on protective devices on a given maintenance cycle interval. By performing this testing, the entity has satisfied PRC-005-4~~X~~ requirement, although the protective device may be unable to be returned to service under normal calibration adjustments. R5 states:

"R5. Each Transmission Owner, Generator Owner, and Distribution Provider shall demonstrate efforts to correct any identified Unresolved Maintenance Issues."

Also, when a failure occurs in a Protection System, power system security may be comprised, and notification of the failure must be conducted in accordance with relevant NERC standards.

If I show the protective device out of service while it is being repaired, then can I add it back as a new protective device when it returns? If not, my relay testing history would show that I was out of compliance for the last maintenance cycle.

The maintenance and testing requirements (R5) state "…shall demonstrate efforts to correct any identified Unresolved Maintenance Issues..." The type of corrective activity is not stated; however, it could include repairs or replacements.

Your documentation requirements will increase, of course, to demonstrate that your device tested bad and had corrective actions initiated. Your regional entity might ask about the status of your corrective actions.

13. Self-Monitoring Capabilities and Limitations

Microprocessor relay proponents have cited the self-monitoring capabilities of these products for nearly 20 years. Theoretically, any element that is monitored does not need a periodic manual test. A problem today is that the community of manufacturers and users has not created clear documentation of exactly what is and is not monitored. Some unmonitored but critical elements are buried in installed systems that are described as self-monitoring.

To utilize the extended time intervals allowed by monitoring, the user must document that the monitoring attributes of the device match the minimum requirements listed in the Table 1.

Until users are able to document how all parts of a system which are required for the protective functions are monitored or verified (with help from manufacturers), they must continue with the unmonitored intervals established in Table 1 and Table 3.

Going forward, manufacturers and users can develop mappings of the monitoring within relays, and monitoring coverage by the relay of user circuits connected to the relay terminals.

To enable the use of the most extensive monitoring (and never again have a hands-on maintenance requirement), the manufacturers of the microprocessor-based self-monitoring components in the Protection System should publish for the user a document or map that shows:

- How all internal elements of the product are monitored for any failure that could impact Protection System performance.
- Which connected circuits are monitored by checks implemented within the product; how to connect and set the product to assure monitoring of these connected circuits; and what circuits or potential problems are not monitored.

This manufacturer's information can be used by the registered entity to document compliance of the monitoring attributes requirements by:

- Presenting or referencing the product manufacturer's documents.
- Explaining in a system design document the mapping of how every component and circuit that is critical to protection is monitored by the microprocessor product(s) or by other design features.
- Extending the monitoring to include the alarm transmission Facilities through which failures are reported within a given time frame to allocate where action can be taken to initiate resolution of the alarm attributed to an Unresolved Maintenance Issue, so that failures of monitoring or alarming systems also lead to alarms and action.
- Documenting the plans for verification of any unmonitored components according to the requirements of Table 1 and Table 3.

13.1 Frequently Asked Questions:

I can't figure out how to demonstrate compliance with the requirements for the highest level of monitoring of Protection Systems. Why does this Maintenance Standard describe a maintenance program approach I cannot achieve?

Demonstrating compliance with the requirements for the highest level of monitoring any particular component of Protection Systems is likely to be very involved, and may include detailed manufacturer documentation of complete internal monitoring within a device, comprehensive design drawing reviews, and other detailed documentation. This standard does not presume to specify what documentation must be developed; only that it must be documented.

There may actually be some equipment available that is capable of meeting these highest levels of monitoring criteria, in which case it may be maintained according to the highest level of monitoring shown on the Tables. However, even if there is no equipment available today that can meet this level of monitoring, the standard establishes the necessary requirements for when such equipment becomes available.

By creating a roadmap for development, this provision makes the standard technology-neutral. The Standard Drafting Team wants to avoid the need to revise the standard in a few years to accommodate technology advances that may be coming to the industry.

14. Notification of Protection System or Automatic Reclosing Failures

When a failure occurs in a Protection System or Automatic Reclosing, power system security may be compromised, and notification of the failure must be conducted in accordance with relevant NERC standard(s). Knowledge of the failure may impact the system operator's decisions on acceptable Loading conditions.

This formal reporting of the failure and repair status to the system operator by the Protection System or Automatic Reclosing owner also encourages the system owner to execute repairs as rapidly as possible. In some cases, a microprocessor relay or carrier set can be replaced in hours; wiring termination failures may be repaired in a similar time frame. On the other hand, a component in an electromechanical or early-generation electronic relay may be difficult to find and may hold up repair for weeks. In some situations, the owner may have to resort to a temporary protection panel, or complete panel replacement.

15. Maintenance Activities

Some specific maintenance activities are a requirement to ensure reliability. An example would be that a BES entity could be prudent in its protective relay maintenance, but if its battery maintenance program is lacking, then reliability could still suffer. The NERC glossary outlines a Protection System as containing specific components. PRC-005-4~~X~~ requires specific maintenance activities be accomplished within a specific time interval. As noted previously, higher technology equipment can contain integral monitoring capability that actually performs maintenance verification activities routinely and often; therefore, *manual intervention* to perform certain activities on these type components may not be needed.

15.1 Protective Relays (Table 1-1)

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 Element of the BES. Devices that sense thermal, vibration, seismic, gas, or any other non-electrical inputs are excluded.

Non-microprocessor based equipment is treated differently than microprocessor-based equipment in the following ways; the relays should meet the asset owners' tolerances:

- Non-microprocessor devices must be tested with voltage and/or current applied to the device.
- Microprocessor devices may be tested through the integral testing of the device.
    - There is no specific protective relay commissioning test or relay routine test mandated.
    - There is no specific documentation mandated.

15.1.1 Frequently Asked Questions:

What calibration tolerance should be applied on electromechanical relays?

Each entity establishes their own acceptable tolerances when applying protective relaying on their system. For some Protection System components, adjustment is required to bring measurement accuracy within the parameters established by the asset owner based on the specific application of the component. A calibration failure is the result if testing finds the specified parameters to be out of tolerance.

15.2 Voltage & Current Sensing Devices (Table 1-3)

These are the current and voltage sensing devices, usually known as instrument transformers. There is presently a technology available (fiber-optic Hall-effect) that does not utilize conventional transformer technology; these devices and other technologies that produce quantities that represent the primary values of voltage and current are considered to be a type of voltage and current sensing devices included in this standard.

The intent of the maintenance activity is to verify the input to the protective relay from the device that produces the current or voltage signal sample.

There is no specific test mandated for these components. The important thing about these signals is to know that the expected output from these components actually reaches the protective relay. Therefore, the proof of the proper operation of these components also demonstrates the integrity of the wiring (or other medium used to convey the signal) from the current and voltage sensing device, all the way to the protective relay. The following observations apply:

- There is no specific ratio test, routine test or commissioning test mandated.
- There is no specific documentation mandated.
- It is required that the signal be present at the relay.
- This expectation can be arrived at from any of a number of means; including, but not limited to, the following: By calculation, by comparison to other circuits, by commissioning tests, by thorough inspection, or by any means needed to verify the circuit meets the asset owner's Protection System maintenance program.
- An example of testing might be a saturation test of a CT with the test values applied at the relay panel; this, therefore, tests the CT, as well as the wiring from the relay all the back to the CT.
- Another possible test is to measure the signal from the voltage and/or current sensing devices, during Load conditions, at the input to the relay.
- Another example of testing the various voltage and/or current sensing devices is to query the microprocessor relay for the Real-time Loading; this can then be compared to other devices to verify the quantities applied to this relay. Since the input devices have supplied the proper values to the protective relay, then the verification activity has been satisfied. Thus, event reports (and oscillographs) can be used to verify that the voltage and current sensing devices are performing satisfactorily.
- Still another method is to measure total watts and VArs around the entire bus; this should add up to zero watts and zero VArs, thus proving the voltage and/or current sensing devices system throughout the bus.
- Another method for proving the voltage and/or current-sensing devices is to complete commissioning tests on all of the transformers, cabling, fuses and wiring.
- Any other method that verifies the input to the protective relay from the device that produces the current or voltage signal sample.

15.2.1 Frequently Asked Questions:

What is meant by "…verify the current and voltage circuit inputs from the voltage and current sensing devices to the protective relays …" Do we need to perform ratio, polarity and saturation tests every few years?

No. You must verify that the protective relay is receiving the expected values from the voltage and current-sensing devices (typically voltage and current transformers). This can be as difficult as is proposed by the question (with additional testing on the cabling and substation wiring to ensure that the values arrive at the relays); or simplicity can be achieved by other verification methods. While some examples follow, these are not intended to represent an all-inclusive list; technology advances and ingenuity should not be excluded from making comparisons and verifications:

- Compare the secondary values, at the relay, to a metering circuit, fed by different current transformers, monitoring the same line as the questioned relay circuit.
- Compare the individual phase secondary values at the relay panel (with additional testing on the panel wiring to ensure that the values arrive at those relays) with the other phases, and verify that residual currents are within expected bounds.
- Observe all three phase currents and the residual current at the relay panel with an oscilloscope, observing comparable magnitudes and proper phase relationship, with additional testing on the panel wiring to ensure that the values arrive at the relays.
- Compare the values, as determined by the questioned relay (such as, but not limited to, a query to the microprocessor relay) to another protective relay monitoring the same line, with currents supplied by different CTs.
- Compare the secondary values, at the relay with values measured by test instruments (such as, but not limited to multi-meters, voltmeter, clamp-on ammeters, etc.) and verified by calculations and known ratios to be the values expected. For example, a single PT on a 100KV bus will have a specific secondary value that, when multiplied by the PT ratio, arrives at the expected bus value of 100KV.
- Query SCADA for the power flows at the far end of the line protected by the questioned relay, compare those SCADA values to the values as determined by the questioned relay.
- Totalize the Watts and VARs on the bus and compare the totals to the values as seen by the questioned relay.

The point of the verification procedure is to ensure that all of the individual components are functioning properly; and that an ongoing proactive procedure is in place to re-check the various components of the protective relay measuring Systems.

Is wiring insulation or hi-pot testing required by this Maintenance Standard?

No, wiring insulation and equipment hi-pot testing are not specifically required by the Maintenance Standard. However, if the method of verifying CT and PT inputs to the relay involves some other method than actual observation of current and voltage transformer secondary inputs to the relay, it might be necessary to perform some sort of cable integrity test to verify that the instrument transformer secondary signals are actually making it to the relay and not being shunted off to ground. For instance, you could use CT excitation tests and PT turns ratio tests and compare to baseline values to verify that the instrument transformer outputs are acceptable. However, to conclude that these acceptable transformer instrument output signals are actually making it to the relay inputs, it also would be necessary to verify the insulation of the wiring between the instrument transformer and the relay.

My plant generator and transformer relays are electromechanical and do not have metering functions, as do microprocessor- based relays. In order for me to compare the instrument transformer inputs to these relays to the secondary values of other metered instrument transformers monitoring the same primary voltage and current signals, it would be necessary to temporarily connect test equipment, like voltmeters and clamp on ammeters, to measure the input signals to the relays. This practice seems very risky, and a plant trip could result if the technician were to make an error while measuring these current and voltage signals. How can I avoid this risk? Also, what if no other instrument transformers are available which monitor the same primary voltage or current signal?

Comparing the input signals to the relays to the outputs of other independent instrument transformers monitoring the same primary current or voltage is just one method of verifying the instrument transformer inputs to the relays, but is not required by the standard. Plants can choose how to best manage their risk. If online testing is deemed too risky, offline tests, such as, but not limited to, CT excitation test and PT turns ratio tests can be compared to baseline data and be used in conjunction with CT and PT secondary wiring insulation verification tests to adequately "verify the current and voltage circuit inputs from the voltage and current sensing devices to the protective relays …" while eliminating the risk of tripping an in service generator or transformer. Similarly, this same offline test methodology can be used to verify the relay input voltage and current signals to relays when there are no other instrument transformers monitoring available for purposes of signal comparison.

15.3 Control circuitry associated with protective functions (Table 1-5)

This component of Protection Systems includes the trip coil(s) of the circuit breaker, circuit switcher or any other interrupting device. It includes the wiring from the batteries to the relays. It includes the wiring (or other signal conveyance) from every trip output to every trip coil. It includes any device needed for the correct processing of the needed trip signal to the trip coil of the interrupting device; this requirement is meant to capture inputs and outputs to and from a protective relay that are necessary for the correct operation of the protective functions. In short, every trip path must be verified; the method of verification is optional to the asset owner. An example of testing methods to accomplish this might be to verify, with a volt-meter, the existence of the proper voltage at the open contacts, the open circuited input circuit and at the trip coil(s). As every parallel trip path has similar failure modes, each trip path from relay to trip coil must be verified. Each trip coil must be tested to trip the circuit breaker (or other interrupting device) at least once. There is a requirement to operate the circuit breaker (or other interrupting device) at least once every six years as part of the complete functional test. If a suitable monitoring system is installed that verifies every parallel trip path, then the manual-intervention testing of those parallel trip paths can be eliminated; however, the actual operation of the circuit breaker must still occur at least once every six years. This six-year tripping requirement can be completed as easily as tracking the Real-time Fault-clearing operations on the circuit breaker, or tracking the trip coil(s) operation(s) during circuit breaker routine maintenance actions.

The circuit-interrupting device should not be confused with a motor-operated disconnect. The intent of this standard is to require maintenance intervals and activities on Protection Systems equipment, and not just all system isolating equipment.

It is necessary, however, to classify a device that actuates a high-speed auto-closing ground switch as an interrupting device, if this ground switch is utilized in a Protection System and forces a ground Fault to occur that then results in an expected Protection System operation to clear the forced ground Fault. The SDT believes that this is essentially a transferred-tripping device without the use of communications equipment. If this high-speed ground switch is "…designed to provide protection for the BES…" then this device needs to be treated as any other Protection System component. The control circuitry would have to be tested within 12 years, and any electromechanically operated device will have to be tested every six years. If the spring-operated ground switch can be disconnected from the solenoid triggering unit, then the solenoid triggering unit can easily be tested without the actual closing of the ground blade.

The dc control circuitry also includes each auxiliary tripping relay (94) and each lock-out relay (86) that may exist in any particular trip scheme. If the lock-out relays (86) are electromechanical type components, then they must be trip tested. The PSMT SDT considers these components to share some similarities in failure modes as electromechanical protective relays; as such, there is a six-year maximum interval between mandated maintenance tasks unless PBM is applied.

Contacts of the 86 and/or 94 that pass the trip current on to the circuit interrupting device trip coils will have to be checked as part of the 12 year requirement. Contacts of the 86 and/or 94 lock relay that operate non-BES interrupting devices are not required. Normally-open contacts that are not used to pass a trip signal and normally-closed contacts do not have to be verified. Verification of the tripping paths is the requirement.

New technology is also accommodated here; there are some tripping systems that have replaced the traditional hard-wired trip circuitry with other methods of trip-signal conveyance such as fiber-optics. It is the intent of the PSMT SDT to include this, and any other, technology that is used to convey a trip signal from a protective relay to a circuit breaker (or other interrupting device) within this category of equipment. The requirement for these systems is verification of the tripping path.

Monitoring of the control circuit integrity allows for no maintenance activity on the control circuit (excluding the requirement to operate trip coils and electromechanical lockout and/or tripping auxiliary relays). Monitoring of integrity means to monitor for continuity and/or presence of voltage on each trip path. For Ethernet or fiber-optic control systems, monitoring of integrity means to monitor communication ability between the relay and the circuit breaker.

15.3.1 Frequently Asked Questions:

Is it permissible to verify circuit breaker tripping at a different time (and interval) than when we verify the protective relays and the instrument transformers?

Yes, provided the entire Protective System is tested within the individual component's maximum allowable testing intervals.

The Protection System Maintenance Standard describes requirements for verifying the tripping of circuit breakers. What is this telling me about maintenance of circuit breakers?

Requirements in PRC-005-4~~X~~ are intended to verify the integrity of tripping circuits, including the breaker trip coil, as well as the presence of auxiliary supply (usually a battery) for energizing the trip coil if a protection function operates. Beyond this, PRC-005-4~~X~~ sets no requirements for verifying circuit breaker performance, or for maintenance of the circuit breaker.

How do I test each dc Control Circuit trip path, as established in Table 1-5 "Protection System Control Circuitry (Trip coils and auxiliary relays)"?

Table 1-5 specifies that each breaker trip coil and lockout relays that carry trip current to a trip coil must be operated within the specified time period. The required operations may be via targeted maintenance activities, or by documented operation of these devices for other purposes such as Fault clearing.

Are high-speed ground switch trip coils included in the dc control circuitry?

Yes. PRC-005-4~~X~~ includes high-speed grounding switch trip coils within the dc control circuitry to the degree that the initiating Protection Systems are characterized as "transmission Protection Systems."

Does the control circuitry and trip coil of a non-BES breaker, tripped via a BES protection component, have to be tested per Table 1.5? (Refer to Table 3 for examples 1 and 2) Example 1: A non-BES circuit breaker that is tripped via a Protection System to which PRC-005-4~~X~~ applies might be (but is not limited to) a 12.5KV circuit breaker feeding (non-black-start) radial Loads but has a trip that originates from an under-frequency (81) relay.

- The relay must be verified.
- The voltage signal to the relay must be verified.
- All of the relevant dc supply tests still apply.
- The unmonitored trip circuit between the relay and any lock-out or auxiliary relay must be verified every 12 years.
- The unmonitored trip circuit between the lock-out (or auxiliary relay) and the non-BES breaker does not have to be proven with an electrical trip.
- In the case where there is no lock-out or auxiliary tripping relay used, the trip circuit to the non-BES breaker does not have to be proven with an electrical trip.
- The trip coil of the non-BES circuit breaker does not have to be individually proven with an electrical trip.

Example 2: A Transmission Owner may have a non-BES breaker that is tripped via a Protection System to which PRC-005-4~~X~~ applies, which may be (but is not limited to) a 13.8 KV circuit breaker feeding (non-black-start) radial Loads but has a trip that originates from a BES 115KV line relay.

- The relay must be verified
- The voltage signal to the relay must be verified

- All of the relevant dc supply tests still apply
- The unmonitored trip circuit between the relay and any lock-out (86) or auxiliary (94) relay must be verified every 12 years
- The unmonitored trip circuit between the lock-out (86) (or auxiliary (94)) relay and the non-BES breaker does not have to be proven with an electrical trip
- In the case where there is no lockout (86) or auxiliary (94) tripping relay used, the trip circuit to the non-BES breaker does not have to be proven with an electrical trip.
- The trip coil of the non-BES circuit breaker does not have to be individually proven with an electrical trip

Example 3: A Generator Owner may have a non-BES circuit breaker that is tripped via a Protection System to which PRC-005-4~~X~~ applies, such as the generator field breaker and low-side breakers on station service/excitation transformers connected to the generator bus.

Trip testing of the generator field breaker and low side station service/excitation transformer breaker(s) via lockout or auxiliary tripping relays are not required since these breakers may be associated with radially fed loads and are not considered to be BES breakers. An example of an otherwise non-BES circuit breaker that is tripped via a BES protection component might be (but is not limited to) a 6.9kV station service transformer source circuit breaker but has a trip that originates from a generator differential (87) relay.

- The differential relay must be verified.
- The current signals to the relay must be verified.
- All of the relevant dc supply tests still apply.
- The unmonitored trip circuit between the relay and any lock-out or auxiliary relay must be verified every 12 years.
- The unmonitored trip circuit between the lock-out (or auxiliary relay) and the non-BES breaker does not have to be proven with an electrical trip.
- In the case where there is no lock-out or auxiliary tripping relay used, the trip circuit to the non-BES breaker does not have to be proven with an electrical trip.
- The trip coil of the non-BES circuit breaker does not have to be individually proven with an electrical trip.

However, it is very prudent to verify the tripping of such breakers for the integrity of the overall generation plant.

Do I have to verify operation of breaker "a" contacts or any other normally closed auxiliary contacts in the trip path of each breaker as part of my control circuit test?

Operation of normally-closed contacts does not have to be verified. Verification of the tripping paths is the requirement. The continuity of the normally closed contacts will be verified when the tripping path is verified.

15.4 Batteries and DC Supplies (Table 1-4)

The NERC definition of a Protection System is:

- Protective relays which respond to electrical quantities,

- Communications Systems necessary for correct operation of protective functions,
- Voltage and current sensing devices providing inputs to protective relays,
- Station dc supply associated with protective functions (including station batteries, battery chargers, and non-battery-based dc supply), and
- Control circuitry associated with protective functions through the trip coil(s) of the circuit breakers or other interrupting devices.

The station battery is not the only component that provides dc power to a Protection System. In the new definition for Protection System, "station batteries" are replaced with "station dc supply" to make the battery charger and dc producing stored energy devices (that are not a battery) part of the Protection System that must be maintained.

The PSMT SDT recognizes that there are several technological advances in equipment and testing procedures that allow the owner to choose how to verify that a battery string is free of open circuits. The term "continuity" was introduced into the standard to allow the owner to choose how to verify continuity of a battery set by various methods, and not to limit the owner to other conventional methods of showing continuity. Continuity, as used in Table 1-4 of the standard, refers to verifying that there is a continuous current path from the positive terminal of the station battery set to the negative terminal. Without verifying continuity of a station battery, there is no way to determine that the station battery is available to supply dc power to the station. An open battery string will be an unavailable power source in the event of loss of the battery charger.

Batteries cannot be a unique population segment of a Performance-Based Maintenance Program (PBM) because there are too many variables in the electrochemical process to completely isolate all of the performance-changing criteria necessary for using PBM on battery Systems. However, nothing precludes the use of a PBM process for any other part of a dc supply besides the batteries themselves.

15.4.1 Frequently Asked Questions:

What constitutes the station dc supply, as mentioned in the definition of Protective System?

The previous definition of Protection System includes batteries, but leaves out chargers. The latest definition includes chargers, as well as dc systems that do not utilize batteries. This revision of PRC-005-4~~X~~ is intended to capture these devices that were not included under the previous definition. The station direct current (dc) supply normally consists of two components: the battery charger and the station battery itself. There are also emerging technologies that provide a source of dc supply that does not include either a battery or charger.

Battery Charger - The battery charger is supplied by an available ac source. At a minimum, the battery charger must be sized to charge the battery (after discharge) and supply the constant dc load. In many cases, it may be sized also to provide sufficient dc current to handle the higher energy requirements of tripping breakers and switches when actuated by the protective relays in the Protection System.

Station Battery - Station batteries provide the dc power required for tripping and for supplying normal dc power to the station in the event of loss of the battery charger. There are several technologies of battery that require unique forms of maintenance as established in Table 1-4.

Emerging Technologies - Station dc supplies are currently being developed that use other energy storage technologies besides the station battery to prevent loss of the station dc supply when ac power is lost. Maintenance of these station dc supplies will require different kinds of tests and inspections. Table 1-4 presents maintenance activities and maximum allowable testing intervals for these new station dc supply technologies. However, because these technologies are relatively new, the maintenance activities for these station dc supplies may change over time.

What did the PSMT SDT mean by "continuity" of the dc supply?

The PSMT SDT recognizes that there are several technological advances in equipment and testing procedures that allow the owner to choose how to verify that a battery string is free of open circuits. The term "continuity" was introduced into the standard to allow the owner to choose how to verify continuity (no open circuits) of a battery set by various methods, and not to limit the owner to other conventional methods of showing continuity – lack of an open circuit. Continuity, as used in Table 1-4 of the standard, refers to verifying that there is a continuous current path from the positive terminal of the station battery set to the negative terminal (no open circuit). Without verifying continuity of a station battery, there is no way to determine that the station battery is available to supply dc power to the station. Whether it is caused from an open cell or a bad external connection, an open battery string will be an unavailable power source in the event of loss of the battery charger.

The current path through a station battery from its positive to its negative connection to the dc control circuits is composed of two types of elements. These path elements are the electrochemical path through each of its cells and all of the internal and external metallic connections and terminations of the batteries in the battery set. If there is loss of continuity (an open circuit) in any part of the electrochemical or metallic path, the battery set will not be available for service. In the event of the loss of the ac source or battery charger, the battery must be capable of supplying dc current, both for continuous dc loads and for tripping breakers and switches. Without continuity, the battery cannot perform this function.

At generating stations and large transmission stations where battery chargers are capable of handling the maximum current required by the Protection System, there are still problems that could potentially occur when the continuity through the connected battery is interrupted.

- Many battery chargers produce harmonics which can cause failure of dc power supplies in microprocessor-based protective relays and other electronic devices connected to station dc supply. In these cases, the substation battery serves as a filter for these harmonics. With the loss of continuity in the battery, the filter provided by the battery is no longer present.
- Loss of electrical continuity of the station battery will cause, in most battery chargers, regardless of the battery charger's output current capability, a delayed response in full output current from the charger. Almost all chargers have an intentional one- to two-second delay to switch from a low substation dc load current to the maximum output of the charger. This delay would cause the opening of circuit breakers to be delayed, which could violate system performance standards.

Monitoring of the station dc supply voltage will not indicate that there is a problem with the dc current path through the battery, unless the battery charger is taken out of service. At that time, a break in the continuity of the station battery current path will be revealed because there will be no voltage on the station dc circuitry. This particular test method, while proving battery continuity, may not be acceptable to all installations.

Although the standard prescribes what must be accomplished during the maintenance activity, it does not prescribe how the maintenance activity should be accomplished. There are several methods that can be used to verify the electrical continuity of the battery. These are not the only possible methods, simply a sampling of some methods:

- One method is to measure that there is current flowing through the battery itself by a simple clamp on milliamp-range ammeter. A battery is always either charging or discharging. Even when a battery is charged, there is still a measurable float charge current that can be detected to verify that there is continuity in the electrical path through the battery.
- A simple test for continuity is to remove the battery charger from service and verify that the battery provides voltage and current to the dc system. However, the behavior of the various dc-supplied equipment in the station should be considered before using this approach.
- Manufacturers of microprocessor-controlled battery chargers have developed methods for their equipment to periodically (or continuously) test for battery continuity. For example, one manufacturer periodically reduces the float voltage on the battery until current from the battery to the dc load can be measured to confirm continuity.
- Applying test current (as in some ohmic testing devices, or devices for locating dc grounds) will provide a current that when measured elsewhere in the string, will prove that the circuit is continuous.
- Internal ohmic measurements of the cells and units of lead-acid batteries (VRLA & VLA) can detect lack of continuity within the cells of a battery string; and when used in conjunction with resistance measurements of the battery's external connections, can prove continuity. Also some methods of taking internal ohmic measurements, by their very nature, can prove the continuity of a battery string without having to use the results of resistance measurements of the external connections.
- Specific gravity tests could infer continuity because without continuity there could be no charging occurring; and if there is no charging, then specific gravity will go down below acceptable levels over time.

No matter how the electrical continuity of a battery set is verified, it is a necessary maintenance activity that must be performed at the intervals prescribed by Table 1-4 to insure that the station dc supply has a path that can provide the required current to the Protection System at all times.

When should I check the station batteries to see if they have sufficient energy to perform as manufactured?

The answer to this question depends on the type of battery (valve-regulated lead-acid, vented lead-acid, or nickel-cadmium) and the maintenance activity chosen.

For example, if you have a valve-regulated lead-acid (VRLA) station battery, and you have chosen to evaluate the measured cell/unit internal ohmic values to the battery cell's baseline, you will have to perform verification at a maximum maintenance interval of no greater than every six months. While this interval might seem to be quite short, keep in mind that the six-month interval is important for VRLA batteries; this interval provides an accumulation of data that better shows when a VRLA battery is incapable of performing as manufactured.

If, for a VRLA station battery, you choose to conduct a performance capacity test on the entire station battery as the maintenance activity, then you will have to perform verification at a maximum maintenance interval of no greater than every three calendar years.

How is a baseline established for cell/unit internal ohmic measurements?

Establishment of cell/unit internal ohmic baseline measurements should be completed when lead-acid batteries are newly installed. To ensure that the baseline ohmic cell/unit values are most indicative of the station battery's ability to perform as manufactured, they should be made at some point in time after the installation to allow the cell chemistry to stabilize after the initial freshening charge. An accepted industry practice for establishing baseline values is after six-months of installation, with the battery fully charged and in service. However, it is recommended that each owner, when establishing a baseline, should consult the battery manufacturer for specific instructions on establishing an ohmic baseline for their product, if available.

When internal ohmic measurements are taken, the same make/model test equipment should be used to establish the baseline and used for the future trending of the cells internal ohmic measurements because of variances in test equipment and the type of ohmic measurement used by different manufacturer's equipment. Keep in mind that one manufacturer's "Conductance" test equipment does not produce similar results as another manufacturer's "Conductance" test equipment, even though both manufacturers have produced "Ohmic" test equipment. Therefore, for meaningful results to an established baseline, the same make/model of instrument should be used.

For all new installations of valve-regulated lead-acid (VRLA) batteries and vented lead-acid (VLA) batteries, where trending of the cells internal ohmic measurements to a baseline are to be used to determine the ability of the station battery to perform as manufactured, the establishment of the baseline, as described above, should be followed at the time of installation to insure the most accurate trending of the cell/unit. However, often for older VRLA batteries, the owners of the station batteries have not established a baseline at installation. Also for owners of VLA batteries who want to establish a maintenance activity which requires trending of measured ohmic values to a baseline, there was typically no baseline established at installation of the station battery to trend to.

To resolve the problem of the unavailability of baseline internal ohmic measurements for the individual cell/unit of a station battery, many manufacturers of internal ohmic measurement devices have established libraries of baseline values for VRLA and VLA batteries using their testing device. Also, several of the battery manufacturers have libraries of baselines for their products that can be used to trend to. However, it is important that when using battery manufacturer-supplied data that it is verified that the baseline readings to be used were taken with the same ohmic testing device that will be used for future measurements (for example "Conductance Readings" from one manufacturer's test equipment do not correlate to "Impedance Readings" from a different manufacturer's test equipment). Although many manufacturers may have provided baseline values, which will allow trending of the internal ohmic measurements over the remaining life of a station battery, these baselines are not the actual cell/unit measurements for the battery being trended. It is important to have a baseline tailored to the station battery to more accurately use the tool of ohmic measurement trending. That more customized baseline can only be created by following the establishment of a baseline for each cell/unit at the time of installation of the station battery.

Why determine the State of Charge?

Even though there is no present requirement to check the state of charge of a battery, it can be a very useful tool in determining the overall condition of a battery system. The following discussions are offered as a general reference.

When a battery is fully charged, the battery is available to deliver its existing capacity. As a battery is discharged, its ability to deliver its maximum available capacity is diminished. It is necessary to determine if the state of charge has dropped to an unacceptable level.

What is State of Charge and how can it be determined in a station battery?

The state of charge of a battery refers to the ratio of residual capacity at a given instant to the maximum capacity available from the battery. When a battery is fully charged, the battery is available to deliver its existing capacity. As a battery is discharged, its ability to deliver its maximum available capacity is diminished. Knowing the amount of energy left in a battery compared with the energy it had when it was fully charged gives the user an indication of how much longer a battery will continue to perform before it needs recharging.

For vented lead-acid (VLA) batteries which use accessible liquid electrolyte, a hydrometer can be used to test the specific gravity of each cell as a measure of its state of charge. The hydrometer depends on measuring changes in the weight of the active chemicals. As the battery discharges, the active electrolyte, sulfuric acid, is consumed and the concentration of the sulfuric acid in water is reduced. This, in turn, reduces the specific gravity of the solution in direct proportion to the state of charge. The actual specific gravity of the electrolyte can, therefore, be used as an indication of the state of charge of the battery. Hydrometer readings may not tell the whole story, as it takes a while for the acid to get mixed up in the cells of a VLA battery. If measured right after charging, you might see high specific gravity readings at the top of the cell, even though it is much less at the bottom. Conversely, if taken shortly after adding water to the cell, the specific gravity readings near the top of the cell will be lower than those at the bottom.

Nickel-cadmium batteries, where the specific gravity of the electrolyte does not change during battery charge and discharge, and valve-regulated lead-acid (VRLA) batteries, where the electrolyte is not accessible, cannot have their state of charge determined by specific gravity readings. For these two types of batteries, and for VLA batteries also, where another method besides taking hydrometer readings is desired, the state of charge may be determined by taking voltage and current readings at the battery terminals. The methods employed to obtain accurate readings vary for the different battery types. Manufacturers' information and IEEE guidelines can be consulted for specifics; (see IEEE 1106 Annex B for Nickel Cadmium batteries, IEEE 1188 Annex A for VRLA batteries and IEEE 450 for VLA batteries.

Why determine the Connection Resistance?

High connection resistance can cause abnormal voltage drop or excessive heating during discharge of a station battery. During periods of a high rate of discharge of the station battery, a very high resistance can cause severe damage. The maintenance requirement to verify battery terminal connection resistance in Table 1-4 is established to verify that the integrity of all battery electrical connections is acceptable. This verification includes cell-to-cell (intercell) and external circuit terminations. Your method of checking for acceptable values of intercell and terminal connection resistance could be by individual readings, or a combination of the two. There are test methods presently that can read post termination resistances and resistance values between external posts. There are also test methods presently available that take a combination reading of the post termination connection resistance plus the intercell resistance value plus the post termination connection resistance value. Either of the two methods, or any other method, that can show if the adequacy of connections at the battery posts is acceptable.

Adequacy of the electrical terminations can be determined by comparing resistance measurements for all connections taken at the time of station battery's installation to the same resistance measurements taken at the maintenance interval chosen, not to exceed the maximum maintenance interval of Table 1-4. Trending of the interval measurements to the baseline measurements will identify any degradation in the battery connections. When the connection resistance values exceed the acceptance criteria for the connection, the connection is typically disassembled, cleaned, reassembled and measurements taken to verify that the measurements are adequate when compared to the baseline readings.

What conditions should be inspected for visible battery cells?

The maintenance requirement to inspect the cell condition of all station battery cells where the cells are visible is a maintenance requirement of Table 1-4. Station batteries are different from any other component in the Protection Station because they are a perishable product due to the electrochemical process which is used to produce dc electrical current and voltage. This inspection is a detailed visual inspection of the cells for abnormalities that occur in the aging process of the cell. In VLA battery visual inspections, some of the things that the inspector is typically looking for on the plates are signs of sulfation of the plates, abnormal colors (which are an indicator of sulfation or possible copper contamination) and abnormal conditions such as cracked grids. The visual inspection could look for symptoms of hydration that would indicate that the battery has been left in a completely discharged state for a prolonged period. Besides looking at the plates for signs of aging, all internal connections, such as the bus bar connection to each plate, and the connections to all posts of the battery need to be visually inspected for abnormalities. In a complete visual inspection for the condition of the cell the cell plates, separators and sediment space of each cell must be looked at for signs of deterioration. An inspection of the station battery's cell condition also includes looking at all terminal posts and cell-to-cell electric connections to ensure they are corrosion free. The case of the battery containing the cell, or cells, must be inspected for cracks and electrolyte leaks through cracks and the post seals.

This maintenance activity cannot be extended beyond the maximum maintenance interval of Table 1-4 by a Performance-Based Maintenance Program (PBM) because of the electrochemical aging process of the station battery, nor can there be any monitoring associated with it because there must be a visual inspection involved in the activity. A remote visual inspection could possibly be done, but its interval must be no greater than the maximum maintenance interval of Table 1-4.

Why is it necessary to verify the battery string can perform as manufactured? I only care that the battery can trip the breaker, which means that the battery can perform as designed. I oversize my batteries so that even if the battery cannot perform as manufactured, it can still trip my breakers.

The fundamental answer to this question revolves around the concept of battery performance "as designed" vs. battery performance "as manufactured." The purpose of the various sections of Table 1-4 of this standard is to establish requirements for the Protection System owner to maintain the batteries, to ensure they will operate the equipment when there is an incident that requires dc power, and ensure the batteries will continue to provide adequate service until at least the next maintenance interval. To meet these goals, the correct battery has to be properly selected to meet the design parameters, and the battery has to deliver the power it was manufactured to provide.

When testing batteries, it may be difficult to determine the original design (i.e., load profile) of the dc system. This standard is not intended as a design document, and requirements relating to design are, therefore, not included.

Where the dc load profile is known, the best way to determine if the system will operate as designed is to conduct a service test on the battery. However, a service test alone might not fully determine if the battery is healthy. A battery with 50% capacity may be able to pass a service test, but the battery would be in a serious state of deterioration and could fail at some point in the near future.

To ensure that the battery will meet the required load profile and continue to meet the load profile until the next maintenance interval, the installed battery must be sized correctly (i.e., a correct design), and it must be in a good state of health. Since the design of the dc system is not within the scope of the standard, the only consistent and reliable method to ensure that the battery is in a good state of health is to confirm that it can perform as manufactured. If the battery can perform as manufactured and it has been designed properly, the system should operate properly until the next maintenance interval.

How do I verify the battery string can perform as manufactured?

Optimally, actual battery performance should be verified against the manufacturer's rating curves. The best practice for evaluating battery performance is via a performance test. However, due to both logistical and system reliability concerns, some Protection System owners prefer other methods to determine if a battery can perform as manufactured. There are several battery parameters that can be evaluated to determine if a battery can perform as manufactured. Ohmic measurements and float current are two examples of parameters that have been reported to assist in determining if a battery string can perform as manufactured.

The evaluation of battery parameters in determining battery health is a complex issue, and is not an exact science. This standard gives the user an opportunity to utilize other measured parameters to determine if the battery can perform as manufactured. It is the responsibility of

the Protection System owner, however, to maintain a documented process that demonstrates the chosen parameter(s) and associated methodology used to determine if the battery string can perform as manufactured.

Whatever parameters are used to evaluate the battery (ohmic measurements, float current, float voltages, temperature, specific gravity, performance test, or combination thereof), the goal is to determine the value of the measurement (or the percentage change) at which the battery fails to perform as manufactured, or the point where the battery is deteriorating so rapidly that it will not perform as manufactured before the next maintenance interval.

This necessitates the need for establishing and documenting a baseline. A baseline may be required of every individual cell, a particular battery installation, or a specific make, model, or size of a cell. Given a consistent cell manufacturing process, it may be possible to establish a baseline number for the cell (make/model/type) and, therefore, a subsequent baseline for every installation would not be necessary. However, future installations of the same battery types should be spot-checked to ensure that your baseline remains applicable.

Consistent testing methods by trained personnel are essential. Moreover, it is essential that these technicians utilize the same make/model of ohmic test equipment each time readings are taken in order to establish a meaningful and accurate trend line against the established baseline. The type of probe and its location (post, connector, etc.) for the reading need to be the same for each subsequent test. The room temperature should be recorded with the readings for each test as well. Care should be taken to consider any factors that might lead a trending program to become invalid.

Float current along with other measureable parameters can be used in lieu of or in concert with ohmic measurement testing to measure the ability of a battery to perform as manufactured. The key to using any of these measurement parameters is to establish a baseline and the point where the reading indicates that the battery will not perform as manufactured.

The establishment of a baseline may be different for various types of cells and for different types of installations. In some cases, it may be possible to obtain a baseline number from the battery manufacturer, although it is much more likely that the baseline will have to be established after the installation is complete. To some degree, the battery may still be "forming" after installation; consequently, determining a stable baseline may not be possible until several months after the battery has been in service.

The most important part of this process is to determine the point where the ohmic reading (or other measured parameter(s)) indicates that the battery cannot perform as manufactured. That point could be an absolute number, an absolute change, or a percentage change of an established baseline.

Since there are no universally-accepted repositories of this information, the Protection System owner will have to determine the value/percentage where the battery cannot perform as manufactured (heretofore referred to as a failed cell). This is the most difficult and important part of the entire process.

To determine the point where the battery fails to perform as manufactured, it is helpful to have a history of a battery type, if the data includes the parameter(s) used to evaluate the battery's ability to perform as manufactured against the actual demonstrated performance/capacity of a battery/cell.

For example, when an ohmic reading has been recorded that the user suspects is indicating a failed cell, a performance test of that cell (or string) should be conducted in order to prove/quantify that the cell has failed. Through this process, the user needs to determine the ohmic value at which the performance of the cell has dropped below 80% of the manufactured, rated performance. It is likely that there may be a variation in ohmic readings that indicates a failed cell (possibly significant). It is prudent to use the most conservative values to determine the point at which the cell should be marked for replacement. Periodically, the user should demonstrate that an "adequate" ohmic reading equates to an adequate battery performance (>80% of capacity).

Similarly, acceptance criteria for "good" and "failed" cells should be established for other parameters such as float current, specific gravity, etc., if used to determine the ability of a battery to function as designed.

What happens if I change the make/model of ohmic test equipment after the battery has been installed for a period of time?

If a user decides to switch testers, either voluntarily or because the equipment is not supported/sold any longer, the user may have to establish a new base line and new parameters that indicate when the battery no longer performs as manufactured. The user always has a choice to perform a capacity test in lieu of establishing new parameters.

What are some of the differences between lead-acid and nickel-cadmium batteries?

There is a marked difference in the aging process of lead acid and nickel-cadmium station batteries. The difference in the aging process of these two types of batteries is chiefly due to the electrochemical process of the battery type. Aging and eventual failure of lead acid batteries is due to expansion and corrosion of the positive grid structure, loss of positive plate active material, and loss of capacity caused by physical changes in the active material of the positive plates. In contrast, the primary failure of nickel-cadmium batteries is due to the gradual linear aging of the active materials in the plates. The electrolyte of a nickel-cadmium battery only facilitates the chemical reaction (it functions only to transfer ions between the positive and negative plates), but is not chemically altered during the process like the electrolyte of a lead acid battery. A lead acid battery experiences continued corrosion of the positive plate and grid structure throughout its operational life while a nickel-cadmium battery does not.

Changes to the properties of a lead acid battery when periodically measured and trended to a baseline, can indicate aging of the grid structure, positive plate deterioration, or changes in the active materials in the plate.

Because of the clear differences in the aging process of lead acid and nickel-cadmium batteries, there are no significantly measurable properties of the nickel-cadmium battery that can be measured at a periodic interval and trended to determine aging. For this reason, Table 1-4(c) (Protection System Station dc supply Using nickel-cadmium [NiCad] Batteries) only specifies one minimum maintenance activity and associated maximum maintenance interval necessary to verify that the station battery can perform as manufactured by evaluating cell/unit measurements indicative of battery performance against the station battery baseline. This maintenance activity is to conduct a performance or modified performance capacity test of the entire battery bank.

Why in Table 1-4 of PRC-005-4~~X~~ is there a maintenance activity to inspect the structural intergrity of the battery rack?

The purpose of this inspection is to verify that the battery rack is correctly installed and has no deterioration that could weaken its structural integrity.

Because the battery rack is specifically manufactured for the battery that is mounted on it, weakening of its structural members by rust or corrosion can physically jeopardize the battery.

What is required to comply with the "Unintentional dc Grounds" requirement?

In most cases, the first ground that appears on a battery is not a problem. It is the unintentional ground that appears on the opposite pole that becomes problematic. Even then many systems are designed to operate favorably under some unintentional DC ground situations. It is up to the owner of the Protection System to determine if corrective actions are needed on detected unintentional DC grounds. The standard merely requires that a check be made for the existence of Unintentional DC Grounds. Obviously, a "check-off" of some sort will have to be devised by the inspecting entity to document that a check is routinely done for Unintentional DC Grounds because of the possible consequences to the Protection System.

Where the standard refers to "all cells," is it sufficient to have a documentation method that refers to "all cells," or do we need to have separate documentation for every cell? For example, do I need 60 individual documented check-offs for good electrolyte level, or would a single check-off per bank be sufficient?

A single check-off per battery bank is sufficient for documentation, as long as the single check-off attests to checking all cells/units.

Does this standard refer to Station batteries or all batteries; for example, Communications Site Batteries?

This standard refers to Station Batteries. The drafting team does not believe that the scope of this standard refers to communications sites. The batteries covered under PRC-005-4~~X~~ are the batteries that supply the trip current to the trip coils of the interrupting devices that are a part of the Protection System. The SDT believes that a loss of power to the communications systems at a remote site would cause the communications systems associated with protective relays to alarm at the substation. At this point, the corrective actions can be initiated.

What are cell/unit internal ohmic measurements?

With the introduction of Valve-Regulated Lead-Acid (VRLA) batteries to station dc supplies in the 1980's several of the standard maintenance tools that are used on Vented Lead-Acid (VLA) batteries were unable to be used on this new type of lead-acid battery to determine its state of health. The only tools that were available to give indication of the health of these new VRLA batteries were voltage readings of the total battery voltage, the voltage of the individual cells and periodic discharge tests.

In the search for a tool for determining the health of a VRLA battery several manufacturers studied the electrical model of a lead acid battery's current path through its cell. The overall battery current path consists of resistance and inductive and capacitive reactance. The inductive reactance in the current path through the battery is so minuscule when compared to the huge capacitive reactance of the cells that it is often ignored in most circuit models of the battery cell. Taking the basic model of a battery cell manufacturers of battery test equipment have developed and marketed testing devices to take measurements of the current path to detect degradation in the internal path through the cell.

In the battery industry, these various types of measurements are referred to as ohmic measurements. Terms used by the industry to describe ohmic measurements are ac conductance, ac impedance, and dc resistance. They are defined by the test equipment providers and IEEE and refer to the method of taking ohmic measurements of a lead acid battery. For example, in one manufacturer's ac conductance equipment measurements are taken by applying a voltage of a known frequency and amplitude across a cell or battery unit and observing the ac current flow it produces in response to the voltage. A manufacturer of an ac impedance meter measures ac current of a known frequency and amplitude that is passed through the whole battery string and determines the impedances of each cell or unit by measuring the resultant ac voltage drop across them. On the other hand, dc resistance of a cell is measured by a third manufacturer's equipment by applying a dc load across the cell or unit and measuring the step change in both the voltage and current to calculate the internal dc resistance of the cell or unit.

It is important to note that because of the rapid development of the market for ohmic measurement devices, there were no standards developed or used to mandate the test signals used in making ohmic measurements. Manufacturers using proprietary methods and applying different frequencies and magnitudes for their signals have developed a diversity of measurement devices. This diversity in test signals coupled with the three different types of ohmic measurements techniques (impedance conductance and resistance) make it impossible to always get the same ohmic measurement for a cell with different ohmic measurement devices. However, IEEE has recognized the great value for choosing one device for ohmic measurement, no matter who makes it or the method to calculate the ohmic measurement. The only caution given by IEEE and the battery manufacturers is that when trending the cells of a lead acid station battery consistent ohmic measurement devices should be used to establish the baseline measurement and to trend the battery set for its entire life.

For VRLA batteries both IEEE Standard 1188 (Maintenance, Testing and Replacement of VRLA Batteries) and IEEE Standard 1187 (Installation Design and Installation of VRLA Batteries) recognize the importance of the maintenance activity of establishing a baseline for "cell/unit internal ohmic measurements (impedance, conductance and resistance)" and trending them at frequent intervals over the life of the battery. There are extensive discussions about the need for taking these measurements in these standards. IEEE Standard 1188 requires taking internal ohmic values as described in Annex C4 during regular inspections of the station battery. For VRLA batteries IEEE Standard 1188 in talking about the necessity of establishing a baseline and trending it over time says, "…depending on the degree of change a performance test, cell replacement or other corrective action may be necessary…" (IEEE std 1188-2005, C.4 page 18).

For VLA batteries IEEE Standard 484 (Installation of VLA batteries) gives several guidelines about establishing baseline measurements on newly installed lead acid stationary batteries. The standard also discusses the need to look for significant changes in the ohmic measurements, the caution that measurement data will differ with each type of model of instrument used, and lists a number of factors that affect ohmic measurements.

At the beginning of the 21st century, EPRI conducted a series of extensive studies to determine the relationship of internal ohmic measurements to the capacity of a lead acid battery cell. The studies indicated that internal ohmic measurements were in fact a good indicator of a lead acid battery cell's capacity, but because users often were only interested in the total station battery capacity and the technology does not precisely predict overall battery capacity, if a user only needs "an accurate measure of the overall battery capacity," they should "perform a battery capacity test."

Prior to the EPRI studies some large and small companies which owned and maintained station dc supplies in NERC Protection Systems developed maintenance programs where trending of ohmic measurements of cells/units of the station's battery became the maintenance activity for determining if the station battery could perform as manufactured. By evaluation of the trending of the ohmic measurements over time, the owner could track the performance of the individual components of the station battery and determine if a total station battery or components of it required capacity testing, removal, replacement or in many instances replacement of the entire station battery. By taking this condition based approach these owners have eliminated having to perform capacity testing at prescribed intervals to determine if a battery needs to be replaced and are still able to effectively determine if a station battery can perform as manufactured.

My VRLA batteries have multiple-cells within an individual battery jar (or unit); how am I expected to comply with the cell-to-cell ohmic measurement requirements on these units that I cannot get to?

Measurement of cell/unit (not all batteries allow access to "individual cells" some "units" or jars may have multiple cells within a jar) internal ohmic values of all types of lead acid batteries where the cells of the battery are not visible is a station dc supply maintenance activity in Table 1-4. In cases where individual cells in a multi-cell unit are inaccessible, an ohmic measurement of the entire unit may be made.

I have a concern about my batteries being used to support additional auxiliary loads beyond my protection control systems in a generation station. Is ohmic measurement testing sufficient for my needs?

While this standard is focused on addressing requirements for Protection Systems, if batteries are used to service other load requirements beyond that of Protection Systems (e.g. pumps, valves, inverter loads), the functional entity may consider additional testing to confirm that the capacity of the battery is sufficient to support all loads.

Why verify voltage?

There are two required maintenance activities associated with verification of dc voltages in Table 1-4. These two required activities are to verify station dc supply voltage and float voltage of the battery charger, and have different maximum maintenance intervals. Both of these voltage verification requirements relate directly to the battery charger maintenance.

The verification of the dc supply voltage is simply an observation of battery voltage to prove that the charger has not been lost or is not malfunctioning; a reading taken from the battery charger panel meter or even SCADA values of the dc voltage could be some of the ways that one could satisfy the requirements. Low battery voltage below float voltage indicates that the battery may be on discharge and, if not corrected, the station battery could discharge down to some extremely low value that will not operate the Protection System. High voltage, close to or above the maximum allowable dc voltage for equipment connected to the station dc supply indicates the battery charger may be malfunctioning by producing high dc voltage levels on the Protection System. If corrective actions are not taken to bring the high voltage down, the dc power supplies and other electronic devices connected to the station dc supply may be damaged. The maintenance activity of verifying the float voltage of the battery charger is not to prove that a charger is lost or producing high voltages on the station dc supply, but rather to prove that the charger is properly floating the battery within the proper voltage limits. As above, there are many ways that this requirement can be met.

Why check for the electrolyte level?

In vented lead-acid (VLA) and nickel-cadmium (NiCad) batteries the visible electrolyte level must be checked as one of the required maintenance activities that must be performed at an interval that is equal to or less than the maximum maintenance interval of Table 1-4. Because the electrolyte level in valve-regulated lead-acid (VRLA) batteries cannot be observed, there is no maintenance activity listed in Table 1-4 of the standard for checking the electrolyte level. Low electrolyte level of any cell of a VLA or NiCad station battery is a condition requiring correction. Typically, the electrolyte level should be returned to an acceptable level for both types of batteries (VLA and NiCad) by adding distilled or other approved-quality water to the cell.

Often people confuse the interval for watering all cells required due to evaporation of the electrolyte in the station battery cells with the maximum maintenance interval required to check the electrolyte level. In many of the modern station batteries, the jar containing the electrolyte is so large with the band between the high and low electrolyte level so wide that normal evaporation which would require periodic watering of all cells takes several years to occur. However, because loss of electrolyte due to cracks in the jar, overcharging of the station battery, or other unforeseen events can cause rapid loss of electrolyte; the shorter maximum maintenance intervals for checking the electrolyte level are required. A low level of electrolyte in a VLA battery cell which exposes the tops of the plates can cause the exposed portion of the plates to accelerated sulfation resulting in loss of cell capacity. Also, in a VLA battery where the electrolyte level goes below the end of the cell withdrawal tube or filling funnel, gasses can exit the cell by the tube instead of the flame arrester and present an explosion hazard.

What are the parameters that can be evaluated in Tables 1-4(a) and 1-4(b)?

The most common parameter that is periodically trended and evaluated by industry today to verify that the station battery can perform as manufactured is internal ohmic cell/unit measurements.

In the mid-1990s, several large and small utilities began developing maintenance and testing programs for Protection System station batteries using a condition based maintenance approach of trending internal ohmic measurements to each station battery cell's baseline value. Battery owners use the data collected from this maintenance activity to determine (1) when a station battery requires a capacity test (instead of performing a capacity test on a predetermined, prescribed interval), (2) when an individual cell or battery unit should be replaced, or (3) based on the analysis of the trended data, if the station battery should be replaced without performing a capacity test.

Other examples of measurable parameters that can be periodically trended and evaluated for lead acid batteries are cell voltage, float current, connection resistance. However, periodically trending and evaluating cell/unit Ohmic measurements are the most common battery/cell parameters that are evaluated by industry to verify a lead acid battery string can perform as manufactured.

Why does it appear that there are two maintenance activities in Table 1-4(b) (for VRLA batteries) that appear to be the same activity and have the same maximum maintenance interval?

There are two different and distinct reasons for doing almost the same maintenance activity at the same interval for valve-regulated lead-acid (VRLA) batteries. The first similar activity for VRLA batteries (Table 1-4(b)) that has the same maximum maintenance interval is to "measure battery cell/unit internal ohmic values." Part of the reason for this activity is because the visual inspection of the cell condition is unavailable for VRLA batteries. Besides the requirement to measure the internal ohmic measurements of VRLA batteries to determine the internal health of the cell, the maximum maintenance interval for this activity is significantly shorter than the interval for vented lead-acid (VLA) due to some unique failure modes for VRLA batteries. Some of the potential problems that VRLA batteries are susceptible to that do not affect VLA batteries are thermal runaway, cell dry-out, and cell reversal when one cell has a very low capacity.

The other similar activity listed in Table 1-4(b) is "…verify that the station battery can perform as manufactured by evaluating the measured cell/unit measurements indicative of battery performance (e.g. internal ohmic values) against the station battery baseline." This activity allows an owner the option to choose between this activity with its much shorter maximum maintenance interval or the longer maximum maintenance interval for the maintenance activity to "Verify that the station battery can perform as manufactured by conducting a performance or modified performance capacity test of the entire battery bank."

For VRLA batteries, there are two drivers for internal ohmic readings. The first driver is for a means to trend battery life. Trending against the baseline of VRLA cells in a battery string is essential to determine the approximate state of health of the battery. Ohmic measurement testing may be used as the mechanism for measuring the battery cells. If all the cells in the string exhibit a consistent trend line and that trend line has not risen above a specific deviation (e.g. 30%) over baseline for impedance tests or below baseline for conductance tests, then a judgment can be made that the battery is still in a reasonably good state of health and able to 'perform as manufactured.' It is essential that the specific deviation mentioned above is based on data (test or otherwise) that correlates the ohmic readings for a specific battery/tester combination to the health of the battery. This is the intent of the "perform **as** manufactured six-month test" at Row 4 on Table 1-4b.

The second big driver is VRLA batteries tendency for thermal runaway. This is the intent of the "thermal runaway test" at Row 2 on Table 1-4b. In order to detect a cell in thermal runaway, you need not necessarily have a formal trending program. When a single cell/unit changes significantly or significantly varies from the other cells (e.g. a doubling of resistance/impedance or a 50% decrease in conductance), there is a high probability that the cell/unit/string needs to be replaced as soon as possible. In other words, if the battery is 10 years old and all the cells have approached a significant change in ohmic values over baseline, then you have a battery which is approaching end of life. You need to get ready to buy a new battery, but you do not have to worry about an impending catastrophic failure. On the other hand, if the battery is five years old and you have one cell that has a markedly different ohmic reading than all the other cells, then you need to be worried that this cell is susceptible to thermal runaway. If the float (charging) current has risen significantly and the ohmic measurement has increased/decreased as described above then concern of catastrophic failure should trigger attention for corrective action.

If an entity elects to use a capacity test rather than a cell ohmic value trending program, this does not eliminate the need to be concerned about thermal runaway – the entity still needs to do the six-month readings and look for cells which are outliers in the string but they need not trend results against the factory/as new baseline. Some entities will not mind the extra administrative burden of having the ongoing trending program against baseline - others would rather just do the capacity test and not have to trend the data against baseline. Nonetheless, all entities must look for ohmic outliers on a six-month basis.

It is possible to accomplish both tasks listed (trend testing for capability and testing for thermal runaway candidates) with the very same ohmic test. It becomes an analysis exercise of watching the trend from baselines and watching for the oblique cell measurement.

In table 1-4(f) (Exclusions for Protection System Station dc Supply Monitoring Devices and Systems), must all component attributes listed in the table be met before an exclusion can be granted for a maintenance activity?

Table 1-4(f) was created by the drafting team to allow Protection System dc supply owners to obtain exclusions from periodic maintenance activities by using monitoring devices. The basis of the exclusions granted in the table is that the monitoring devices must incorporate the monitoring capability of microprocessor based components which perform continuous self-monitoring. For failure of the microprocessor device used in dc supply monitoring, the self-checking routine in the microprocessor must generate an alarm which will be reported within 24 hours of device failure to a location where corrective action can be initiated.

Table 1-4(f) lists 8 component attributes along with a specific periodic maintenance activity associated with each of the 8 attributes listed. If an owner of a station dc supply wants to be excluded from periodically performing one of the 8 maintenance activities listed in table 1-4(f), the owner must have evidence that the monitoring and alarming component attributes associated with the excluded maintenance activity are met by the self-checking microprocessor based device with the specific component attribute listed in the table 1-4(f).

For example if an owner of a VLA station battery does not want to "verify station dc supply voltage" every "4 calendar months" (see table 1-4(a)), the owner can install a monitoring and alarming device "with high and low voltage monitoring and alarming of the battery charger voltage to detect charger overvoltage and charger failure" and "no periodic verification of station dc supply voltage is required" (see table 1-4(f) first row). However, if for the same Protection System discussed above, the owner does not install "electrolyte level monitoring and alarming in every cell" and "unintentional dc ground monitoring and alarming" (see second and third rows of table 1-4(f)), the owner will have to "inspect electrolyte level and for unintentional grounds" every "4 calendar months" (see table 1-4(a)).

15.5 Associated communications equipment (Table 1-2)

The equipment used for tripping in a communications-assisted trip scheme is a vital piece of the trip circuit. Remote action causing a local trip can be thought of as another parallel trip path to the trip coil that must be tested. Besides the trip output and wiring to the trip coil(s), there is also a communications medium that must be maintained. Newer technologies now exist that achieve communications-assisted tripping without the conventional wiring practices of older technology. For example, older technologies may have included Frequency Shift Key methods. This technology requires that guard and trip levels be maintained. The actual tripping path(s) to the trip coil(s) may be tested as a parallel trip path within the dc control circuitry tests. Emerging technologies transfer digital information over a variety of carrier mediums that are then interpreted locally as trip signals. The requirements apply to the communicated signal needed for the proper operation of the protective relay trip logic or scheme. Therefore, this standard is applied to equipment used to convey both trip signals (permissive or direct) and block signals.

It was the intent of this standard to require that a test be performed on any communications-assisted trip scheme, regardless of the vintage of technology. The essential element is that the tripping (or blocking) occurs locally when the remote action has been asserted; or that the tripping (or blocking) occurs remotely when the local action is asserted. Note that the required testing can still be done within the concept of testing by overlapping segments. Associated communications equipment can be (but is not limited to) testing at other times and different frequencies as the protective relays, the individual trip paths and the affected circuit interrupting devices.

Some newer installations utilize digital signals over fiber-optics from the protective relays in the control house to the circuit interrupting device in the yard. This method of tripping the circuit breaker, even though it might be considered communications, must be maintained per the dc control circuitry maintenance requirements.

15.5.1 Frequently Asked Questions:

What are some examples of mechanisms to check communications equipment functioning?

For unmonitored Protection Systems, various types of communications systems will have different facilities for on-site integrity checking to be performed at least every four months during a substation visit. Some examples are, but not limited to:

- On-off power-line carrier systems can be checked by performing a manual carrier keying test between the line terminals, or carrier check-back test from one terminal.
- Systems which use frequency-shift communications with a continuous guard signal (over a telephone circuit, analog microwave system, etc.) can be checked by observing for a loss-of-guard indication or alarm. For frequency-shift power-line carrier systems, the guard signal level meter can also be checked.
- Hard-wired pilot wire line Protection Systems typically have pilot-wire monitoring relays that give an alarm indication for a pilot wire ground or open pilot wire circuit loop.
- Digital communications systems typically have a data reception indicator or data error indicator (based on loss of signal, bit error rate, or frame error checking).

For monitored Protection Systems, various types of communications systems will have different facilities for monitoring the presence of the communications channel, and activating alarms that can be monitored remotely. Some examples are, but not limited to:

- On-off power-line carrier systems can be shown to be operational by automated periodic power-line carrier check-back tests with remote alarming of failures.
- Systems which use a frequency-shift communications with a continuous guard signal (over a telephone circuit, analog microwave system, etc.) can be remotely monitored with a loss-of-guard alarm or low signal level alarm.
- Hard-wired pilot wire line Protection Systems can be monitored by remote alarming of pilot-wire monitoring relays.
- Digital communications systems can activate remotely monitored alarms for data reception loss or data error indications.
- Systems can be queried for the data error rates.

For the highest degree of monitoring of Protection Systems, the communications system must monitor all aspects of the performance and quality of the channel that show it meets the design performance criteria, including monitoring of the channel interface to protective relays.

- In many communications systems signal quality measurements, including signal-to-noise ratio, received signal level, reflected transmitter power or standing wave ratio, propagation delay, and data error rates are compared to alarm limits. These alarms are connected for remote monitoring.
- Alarms for inadequate performance are remotely monitored at all times, and the alarm communications system to the remote monitoring site must itself be continuously

monitored to assure that the actual alarm status at the communications equipment location is continuously being reflected at the remote monitoring site.

What is needed for the four-month inspection of communications-assisted trip scheme equipment?

The four-month inspection applies to unmonitored equipment. An example of compliance with this requirement might be, but is not limited to:

With each site visit, check that the equipment is free from alarms; check any metered signal levels, and that power is still applied. While this might be explicit for a particular type of equipment (i.e., FSK equipment), the concept should be that the entity verify that the communications equipment that is used in a Protection System is operable through a cursory inspection and site visit. This site visit can be eliminated on this particular example if the FSK equipment had a monitored alarm on Loss of Guard. Blocking carrier systems with auto checkbacks will present an alarm when the channel fails allowing a visual indication. With no auto checkback, the channel integrity will need to be verified by a manual checkback or a two ended signal check. This check could also be eliminated by bring the auto checkback failure alarm to the monitored central location.

Does a fiber optic I/O scheme used for breaker tripping or control within a station, for example - transmitting a trip signal or control logic between the control house and the breaker control cabinet, constitute a communications system?

This equipment is presently classified as being part of the Protection System control circuitry and tested per the portions of Table 1 applicable to "Protection System Control Circuitry", rather than those portions of the table applicable to communications equipment.

What is meant by "Channel" and "Communications Systems" in Table 1-2?

The transmission of logic or data from a relay in one station to a relay in another station for use in a pilot relay scheme will require a communications system of some sort. Typical relay communications systems use fiber optics, leased audio channels, power line carrier, and microwave. The overall communications system includes the channel and the associated communications equipment.

This standard refers to the "channel" as the medium between the transmitters and receivers in the relay panels such as a leased audio or digital communications circuit, power line and power line carrier auxiliary equipment, and fiber. The dividing line between the channel and the associated communications equipment is different for each type of media.

Examples of the Channel:

- Power Line Carrier (PLC) - The PLC channel starts and ends at the PLC transmitter and receiver output unless there is an internal hybrid. The channel includes the external hybrids, tuners, wave traps and the power line itself.
- Microwave –The channel includes the microwave multiplexers, radios, antennae and associated auxiliary equipment. The audio tone and digital transmitters and receivers in the relay panel are the associated communications equipment.
- Digital/Audio Circuit – The channel includes the equipment within and between the substations. The associated communications equipment includes the relay panel transmitters and receivers and the interface equipment in the relays.

- Fiber Optic – The channel starts at the fiber optic connectors on the fiber distribution panel at the local station and goes to the fiber optic distribution panel at the remote substation. The jumpers that connect the relaying equipment to the fiber distribution panel and any optical-electrical signal format converters are the associated communications equipment

Figure 1-2, A-1 and A-2 at the end of this document show good examples of the communications channel and the associated communications equipment.

In Table 1-2, the Maintenance Activities section of the Protection System Communications Equipment and Channels refers to the quality of the channel meeting "performance criteria." What is meant by performance criteria?

Protection System communications channels must have a means of determining if the channel and communications equipment is operating normally. If the channel is not operating normally, an alarm will be indicated. For unmonitored systems, this alarm will probably be on the panel. For monitored systems, the alarm will be transmitted to a remote location.

Each entity will have established a nominal performance level for each Protection System communications channel that is consistent with proper functioning of the Protection System. If that level of nominal performance is not being met, the system will go into alarm. Following are some examples of Protection System communications channel performance measuring:

- For direct transfer trip using a frequency shift power line carrier channel, a guard level monitor is part of the equipment. A normal receive level is established when the system is calibrated and if the signal level drops below an established level, the system will indicate an alarm.
- An on-off blocking signal over power line carrier is used for directional comparison blocking schemes on transmission lines. During a Fault, block logic is sent to the remote relays by turning on a local transmitter and sending the signal over the power line to a receiver at the remote end. This signal is normally off so continuous levels cannot be checked. These schemes use check-back testing to determine channel performance. A predetermined signal sequence is sent to the remote end and the remote end decodes this signal and sends a signal sequence back. If the sending end receives the correct information from the remote terminal, the test passes and no alarm is indicated. Full power and reduced power tests are typically run. Power levels for these tests are determined at the time of calibration.
- Pilot wire relay systems use a hardwire communications circuit to communicate between the local and remote ends of the protective zone. This circuit is monitored by circulating a dc current between the relay systems. A typical level may be 1 mA. If the level drops below the setting of the alarm monitor, the system will indicate an alarm.
- Modern digital relay systems use data communications to transmit relay information to the remote end relays. An example of this is a line current differential scheme commonly used on transmission lines. The protective relays communicate current magnitude and phase information over the communications path to determine if the

Fault is located in the protective zone. Quantities such as digital packet loss, bit error rate and channel delay are monitored to determine the quality of the channel. These limits are determined and set during relay commissioning. Once set, any channel quality problems that fall outside the set levels will indicate an alarm.

The previous examples show how some protective relay communications channels can be monitored and how the channel performance can be compared to performance criteria established by the entity. This standard does not state what the performance criteria will be; it just requires that the entity establish nominal criteria so Protection System channel monitoring can be performed.

How is the performance criteria of Protection System communications equipment involved in the maintenance program?

An entity determines the acceptable performance criteria, depending on the technology implemented. If the communications channel performance of a Protection System varies from the pre-determined performance criteria for that system, then these results should be investigated and resolved.

How do I verify the A/D converters of microprocessor-based relays?

There are a variety of ways to do this. Two examples would be: using values gathered via data communications and automatically comparing these values with values from other sources, or using groupings of other measurements (such as vector summation of bus feeder currents) for comparison. Many other methods are possible.

15.6 Alarms (Table 2)

In addition to the tables of maintenance for the components of a Protection System, there is an additional table added for alarms. This additional table was added for clarity. This enabled the common alarm attributes to be consolidated into a single spot, and, thus, make it easier to read the Tables 1-1 through 1-5, Table 3, and Table 4. The alarms need to arrive at a site wherein a corrective action can be initiated. This could be a control room, operations center, etc. The alarming mechanism can be a standard alarming system or an auto-polling system; the only requirement is that the alarm be brought to the action-site within 24 hours. This effectively makes manned-stations equivalent to monitored stations. The alarm of a monitored point (for example a monitored trip path with a lamp) in a manned-station now makes that monitored point eligible for monitored status. Obviously, these same rules apply to a non-manned-station, which is that if the monitored point has an alarm that is auto-reported to the operations center (for example) within 24 hours, then it too is considered monitored.

15.6.1 Frequently Asked Questions:

Why are there activities defined for varying degrees of monitoring a Protection System component when that level of technology may not yet be available?

There may already be some equipment available that is capable of meeting the highest levels of monitoring criteria listed in the Tables. However, even if there is no equipment available today that can meet this level of monitoring the standard establishes the necessary requirements for when such equipment becomes available. By creating a roadmap for development, this provision makes the standard technology neutral. The Standard Drafting Team wants to avoid the need to revise the standard in a few years to accommodate technology advances that may be coming to the industry.

Does a fail-safe "form b" contact that is alarmed to a 24/7 operation center classify as an alarm path with monitoring?

If the fail-safe "form-b" contact that is alarmed to a 24/7 operation center causes the alarm to activate for failure of any portion of the alarming path from the alarm origin to the 24/7 operations center, then this can be classified as an alarm path with monitoring.

15.7 Distributed UFLS and Distributed UVLS Systems (Table 3)

Distributed UFLS and distributed UVLS systems have their maintenance activities documented in Table 3 due to their distributed nature allowing reduced maintenance activities and extended maximum maintenance intervals. Relays have the same maintenance activities and intervals as Table 1-1. Voltage and current-sensing devices have the same maintenance activity and interval as Table 1-3. DC systems need only have their voltage read at the relay every 12 years. Control circuits have the following maintenance activities every 12 years:

- Verify the trip path between the relay and lock-out and/or auxiliary tripping device(s).
- Verify operation of any lock-out and/or auxiliary tripping device(s) used in the trip circuit.
- No verification of trip path required between the lock-out (and/or auxiliary tripping device) and the non-BES interrupting device.
- No verification of trip path required between the relay and trip coil for circuits that have no lock-out and/or auxiliary tripping device(s).
- No verification of trip coil required.

No maintenance activity is required for associated communication systems for distributed UFLS and distributed UVLS schemes.

Non-BES interrupting devices that participate in a distributed UFLS or distributed UVLS scheme are excluded from the tripping requirement, and part of the control circuit test requirement; however, the part of the trip path control circuitry between the Load-Shed relay and lock-out or auxiliary tripping relay must be tested at least once every 12 years. In the case where there is no lock-out or auxiliary tripping relay used in a distributed UFLS or UVLS scheme which is not part of the BES, there is no control circuit test requirement. There are many circuit interrupting devices in the distribution system that will be operating for any given under-frequency event that requires tripping for that event. A failure in the tripping action of a single distributed system circuit breaker (or non-BES equipment interruption device) will be far less significant than, for example, any single transmission Protection System failure, such as a failure of a bus differential lock-out relay. While many failures of these distributed system circuit breakers (or non-BES equipment interruption device) could add up to be significant, it is also believed that many circuit breakers are operated often on just Fault clearing duty; and, therefore, these circuit breakers are operated at least as frequently as any requirements that appear in this standard.

There are times when a Protection System component will be used on a BES device, as well as a non-BES device, such as a battery bank that serves both a BES circuit breaker and a non-BES interrupting device used for UFLS. In such a case, the battery bank (or other Protection System component) will be subject to the Tables of the standard because it is used for the BES.

15.7.1 Frequently Asked Questions:

The standard reaches further into the distribution system than we would like for UFLS and UVLS

While UFLS and UVLS equipment are located on the distribution network, their job is to protect the Bulk Electric System. This is not beyond the scope of NERC's 215 authority.

FPA section 215(a) definitions section defines bulk power system as: "(A) facilities and control Systems necessary for operating an interconnected electric energy transmission network (or any portion thereof)." That definition, then, is limited by a later statement which adds the term bulk power system "…does not include facilities used in the local distribution of electric energy." Also, Section 215 also covers users, owners, and operators of bulk power Facilities.

UFLS and UVLS (when the UVLS is installed to prevent system voltage collapse or voltage instability for BES reliability) are not "used in the local distribution of electric energy," despite their location on local distribution networks. Further, if UFLS/UVLS Facilities were not covered by the reliability standards, then in order to protect the integrity of the BES during under-frequency or under-voltage events, that Load would have to be shed at the Transmission bus to ensure the Load-generation balance and voltage stability is maintained on the BES.

15.8 Automatic Reclosing (Table 4)

Please see the document referenced in Section F of PRC-005-3, "Considerations for Maintenance and Testing of Autoreclosing Schemes — November 2012", for a discussion of Automatic Reclosing as addressed in PRC-005-3.

15.8.1 Frequently-asked Questions

Automatic Reclosing is a control, not a protective function; why then is Automatic Reclosing maintenance included in the Protection System Maintenance Program (PSMP)?

Automatic Reclosing is a control function. The standard's title 'Protection System and Automatic Reclosing Maintenance' clearly distinguishes (separates) the Automatic Reclosing from the Protection System. Automatic Reclosing is included in the PSMP because it is a more pragmatic approach as compared to creating a parallel and essentially identical 'Control System Maintenance Program' for the two Automatic Reclosing component types.

When do I need to have the initial maintenance of Automatic Reclosing Components completed upon change of the largest BES generating unit in the BA/RSG?

The maintenance interval, for newly identified Automatic Reclosing Components, starts when a change in the largest BES generating unit is determined by the BA/RSG. The first maintenance records for newly identified Automatic Reclosing Components should be dated no later than the maximum maintenance interval after the identification date. The maximum maintenance intervals for each newly identified Component are defined in Table 4. No activities or records are required prior to the date of identification.

Our maintenance practice consists of initiating the Automatic Reclosing relay and confirming the breaker closes properly and the close signal is released. This practice verifies the control circuitry associated with Automatic Reclosing. Do you agree?"

The described task partially verifies the control circuit maintenance activity. To meet the control circuit maintenance activity, responsible entities need to verify, *upon initiation*, that the reclosing relay does not issue a *premature closing command*. As noted on page 12 of the SAMS/SPCS report, the concern being addressed within the standard is premature auto reclosing that has the potential to cause generating unit or plant instability. Reclosing applications have many variations, responsible entities will need to verify the applicability of associated supervision/conditional logic and the reclosing relay operation; then verify the conditional logic or that the reclosing relay performs in a manner that does not result in a *premature closing command* being issued.

Some examples of conditions which can result in a premature closing command are: an improper supervision or conditional logic input which provides a false state and allows the reclosing relay to issue an improper close command based on incorrect conditions (i.e. voltage supervision, equipment status, sync window verification); timers utilized for closing actuation or reclosing arming/disarming circuitry which could allow the reclosing relay to issue an improper close command; a reclosing relay output contact failure which could result in a made-up-close condition / failure-to-release condition.

Why was a close-in three phase fault present for twice the normal clearing time chosen for the Automatic Reclosing exclusion? It exceeds TPL requirements and ignores the breaker closing time in a trip-close-trip sequence, thus making the exclusion harder to attain.

This condition represents a situation where a close signal is issued with no time delay or with less time delay than is intended, such as if a reclosing contact is welded closed. This failure mode can result in a minimum trip-close-trip sequence with the two faults cleared in primary protection operating time, and the open time between faults equal to the breaker closing cycle time. The sequence for this failure mode results in system impact equivalent to a high-speed autoreclosing sequence with no delay added in the autoreclosing logic. It represents a failure mode which must be avoided because it exceeds TPL requirements.

Do we have to test the various breaker closing circuit interlocks and controls such as anti-pump?

These components are not specifically addressed within Table 4, and need not be individually tested. They are indirectly verified by performing the Automatic Reclosing control circuitry verification as established in Table 4.

For Automatic Reclosing that is not part of an ~~SPS,~~RAS, do we have to close the circuit breaker periodically?

No. For this application, you need only to verify that the Automatic Reclosing, upon initiation, does not issue a premature closing command. This activity is concerned only with assuring that a premature close does not occur, and cause generating plant instability.

For Automatic Reclosing that is part of an ~~SPS,~~RAS, do we have to close the circuit breaker periodically?

Yes. In this application, successful closing is a necessary portion of the ~~SPS,~~RAS, and must be verified.

15.9 Sudden Pressure Relaying (Table 5)

Please see the document referenced in Section F of PRC-005-4~~X~~, “Sudden Pressure Relays and Other Devices that Respond to Non-Electrical Quantities – December 2013”, for a discussion of Sudden Pressure Relaying as addressed in PRC-005-4~~X~~.

15.9.1 Frequently Asked Questions:

~~***How do I verify the pressure or flow sensing mechanism is operable?***~~

~~Operate, or cause to operate the mechanism responding to the rapid-pressure rise. The standard does not specify how to perform the maintenance.~~

How do I verify the pressure or flow sensing mechanism is operable?

Maintenance activities for the fault pressure relay associated with Sudden Pressure Relaying in PRC-005-4~~X~~ are intended to verify that the pressure and/or flow sensing mechanism are functioning correctly. Beyond this, PRC-005-4~~X~~ requires no calibration (adjusting the operating threshold or measurement accuracy of a measuring element to meet the intended performance requirement) or testing (applying signals to a component to observe functional performance or output behavior, or to diagnose problems) activities. For example, some designs of flow sensing mechanisms allow the operation of a test switch to actuate the limit switch of the flow sensing mechanism. Operation of this test switch and verification of the flow sensing mechanism would meet the requirements of the maintenance activity. Another example involves a gas pressure sensing mechanism which is isolated by a test plug. Removal of the plug and verification of the bellows mechanism would meet the requirements of the maintenance activity.

Why the 6-year maximum maintenance interval for fault pressure relays?

The SDT established the six-year maintenance interval for fault pressure relays (see Table 5, PRC-005-4~~X~~) based on the recommendation of the System Protection and Control Subcommittee (SPCS). The technical experts of the SPCS were tasked with developing the technical documents to:

i. Describe the devices and functions (to include sudden pressure relays which trip for fault conditions) that should address FERC’s concern; and

ii. Propose minimum maintenance activities for such devices and maximum maintenance intervals, including the technical basis for each.

Excerpt from the SPCS technical report: “In order to determine present industry practices related to sudden pressure relay maintenance, the SPCS conducted a survey of Transmission Owners and Generator Owners in all eight Regions requesting information related to their maintenance practices. The SPCS received responses from 75 Transmission Owners and 109 Generator Owners. Note that, for the purpose of the survey, sudden pressure relays included the following: the “sudden pressure relay” (SPR) originally manufactured by Westinghouse, the “rapid pressure rise relay” (RPR) manufactured by Qualitrol, and a variety of Buchholz relays.

Table 2 provides a summary of the results of the responses:

Table 2: Sudden Pressure Relay Maintenance Practices – Survey Results		
-	Transmission	Generator Owner

	Owner	
Number of responding owners that trip with Sudden Pressure Relays:	67	84
Percentage of responding owners who trip that have a Maintenance Program:	75%	78%
Percentage of maintenance programs that include testing the pressure actuator:	81%	77%
Average Maintenance interval reported:	5.9 years	4.9 years

Additionally, in order to validate the information noted above, the SPCS contacted the following entities for their feedback: the IEEE Power System Relaying Committee, the IEEE Transformer Committee, the Doble Transformer Committee, the NATF System Protection Practices Group, and the EPRI Generator Owner/Operator Technical Focus Group. All of these organizations indicated the results of the SPCS survey are consistent with their respective experiences.

The SPCS discussed the potential difference between the recommended intervals for fault pressure relaying and intervals for transformer maintenance. The SPCS developed the recommended intervals for fault pressure relaying by comparing fault pressure relaying to Protection System Components with similar physical attributes. The SPCS recognized that these intervals may be shorter than some existing or future transformer maintenance intervals, but believed it to be more important to base intervals for fault pressure relaying on similar Protection System Components than transformer maintenance intervals.

The maintenance interval for fault pressure relays can be extended by utilizing performance-based maintenance thereby allowing entities that have maintenance intervals for transformers in excess of six years, to align them.

~~Why do I have to test the fault pressure relay every 6 years? Our experience is that these devices have no trouble operating as we have had our share of nuisance trips on through-faults.~~

~~The frequency of the testing is set to align with previously set maintenance intervals in PRC-005 and align with a survey of respondents as detailed in the previously noted NERC SPCS paper responding to FERC Order 758.~~

Sudden Pressure Relaying control circuitry is now specifically mentioned in the maintenance tables. Do we have to trip our circuit breaker specifically from the trip output of the sudden pressure relay?

No. Verification may be by breaker tripping, but may be verified in overlapping segments with the Protection System control circuitry.

Can we use Performance Based Maintenance for fault pressure relays?

Yes. Performance Based Maintenance is applicable to fault pressure relays.

15.10 Examples of Evidence of Compliance

To comply with the requirements of this standard, an entity will have to document and save evidence. The evidence can be of many different forms. The Standard Drafting Team recognizes that there are concurrent evidence requirements of other NERC standards that could, at times, fulfill evidence requirements of this standard.

15.10.1 Frequently Asked Questions:

What forms of evidence are acceptable?

Acceptable forms of evidence, as relevant for the requirement being documented include, but are not limited to:

- Process documents or plans
- Data (such as relay settings sheets, photos, SCADA, and test records)
- Database lists, records and/or screen shots that demonstrate compliance information
- Prints, diagrams and/or schematics
- Maintenance records
- Logs (operator, substation, and other types of log)
- Inspection forms
- Mail, memos, or email proving the required information was exchanged, coordinated, submitted or received
- Check-off forms (paper or electronic)
- Any record that demonstrates that the maintenance activity was known, accounted for, and/or performed.

If I replace a failed Protection System component with another component, what testing do I need to perform on the new component?

In order to reset the Table 1 maintenance interval for the replacement component, all relevant Table 1 activities for the component should be performed.

I have evidence to show compliance for PRC-016 ("Special Protection System Misoperation"). Can I also use it to show compliance for this Standard, PRC-005-4~~X~~?

Maintaining evidence for operation of ~~Special Protection Systems~~Remedial Action Systems could concurrently be utilized as proof of the operation of the associated trip coil (provided one can be certain of the trip coil involved). Thus, the reporting requirements that one may have to do for the Misoperation of a Special Protection Scheme under PRC-016 could work for the activity tracking requirements under this PRC-005-4~~X~~.

I maintain Disturbance records which show Protection System operations. Can I use these records to show compliance?

These records can be concurrently utilized as dc trip path verifications, to the degree that they demonstrate the proper function of that dc trip path.

I maintain test reports on some of my Protection System components. Can I use these test reports to show that I have verified a maintenance activity?

Yes.

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16. “Essentials of Statistics for Business and Economics” Anderson, Sweeney, Williams, 2003

17. “Introduction to Statistics and Data Analysis” - Second Edition, Peck, Olson, Devore, 2005

18. “Statistical Analysis for Business Decisions” Peters, Summers, 1968

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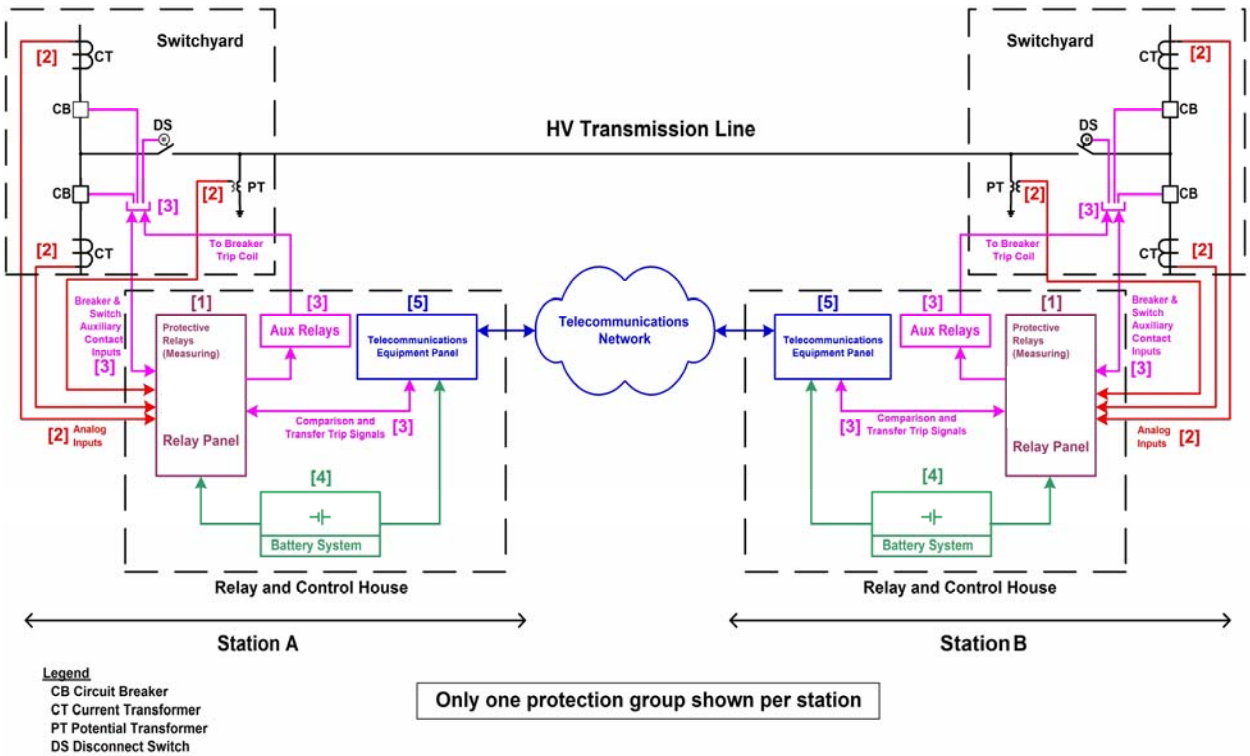
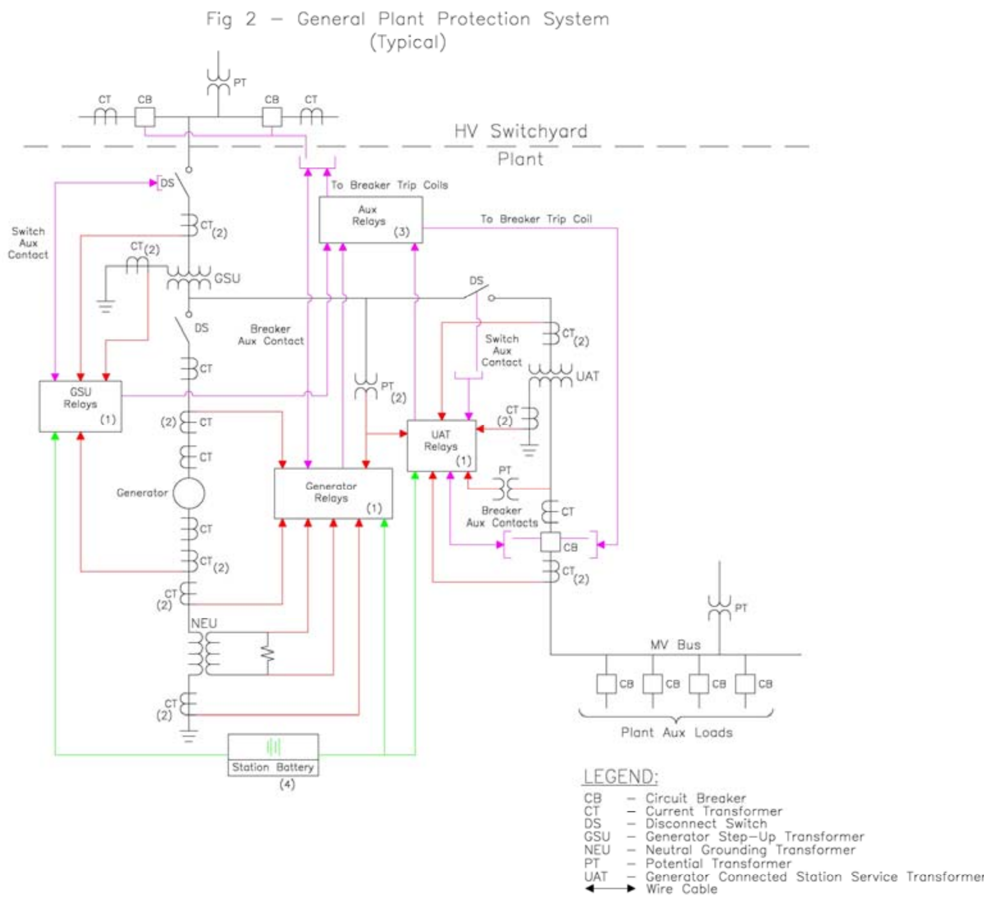
Figures

Figure 1: Typical Transmission System



For information on components, see ***[Figure 1 & 2 Legend – components of Protection Systems]()***

Figure 2: Typical Generation System



Note: Figure 2 may show elements that are not included within PRC-005-2, and also may not be all-inclusive; see the Applicability section of the standard for specifics.

For information on components, see ***Figure 1 & 2 Legend – components of Protection Systems***

Figure 1 & 2 Legend – Components of Protection Systems

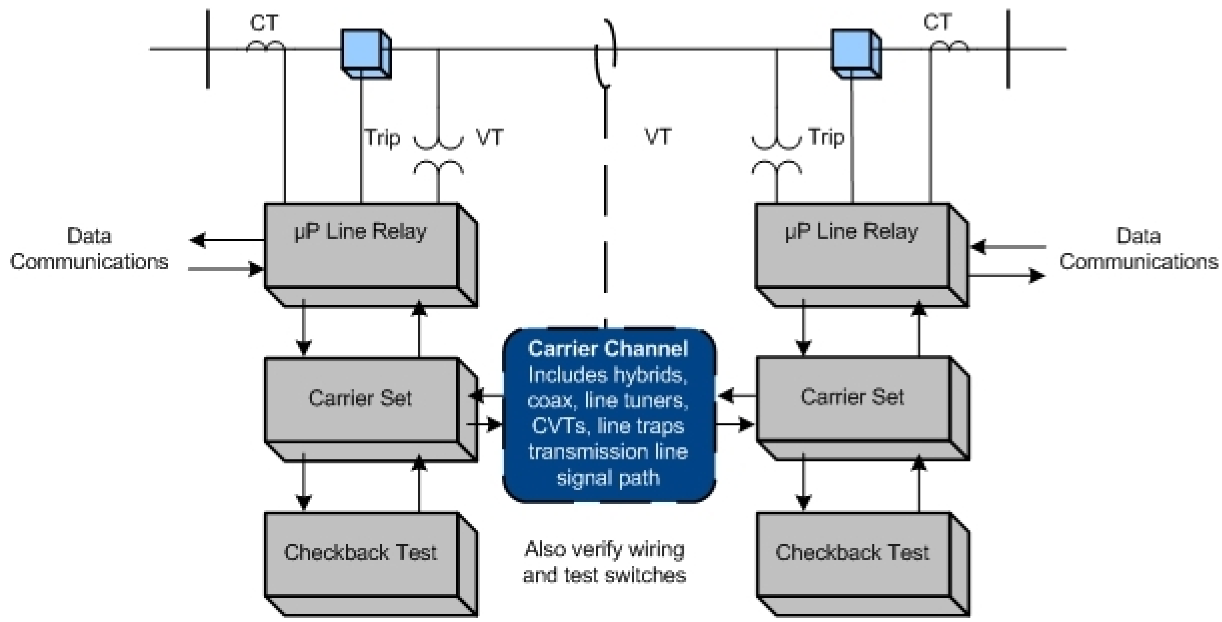
Number in Figure	Component of Protection System	Includes	Excludes
1	Protective relays which respond to electrical quantities	All protective relays that use current and/or voltage inputs from current & voltage sensors and that trip the 86, 94 or trip coil.	Devices that use non-electrical methods of operation including thermal, pressure, gas accumulation, and vibration. Any ancillary equipment not specified in the definition of Protection Systems. Control and/or monitoring equipment that is not a part of the automatic tripping action of the Protection System
2	Voltage and current sensing devices providing inputs to protective relays	The signals from the voltage & current sensing devices to the protective relay input.	Voltage & current sensing devices that are not a part of the Protection System, including sync-check systems, metering systems and data acquisition systems.
3	Control circuitry associated with protective functions	All control wiring (or other medium for conveying trip signals) associated with the tripping action of 86 devices, 94 devices or trip coils (from all parallel trip paths). This would include fiber-optic systems that carry a trip signal as well as hard-wired systems that carry trip current.	Closing circuits, SCADA circuits, other devices in control scheme not passing trip current
4	Station dc supply	Batteries and battery chargers and any control power system which has the function of supplying power to the protective relays, associated trip circuits and trip coils.	Any power supplies that are not used to power protective relays or their associated trip circuits and trip coils.
5	Communications systems necessary for correct operation of protective functions	Tele-protection equipment used to convey specific information, in the form of analog or digital signals, necessary for the correct operation of protective functions.	Any communications equipment that is not used to convey information necessary for the correct operation of protective functions.

Additional information can be found in References

Appendix A

The following illustrates the concept of overlapping verifications and tests as summarized in Section 10 of the paper. As an example, Figure A-1 shows protection for a critical transmission line by carrier blocking directional comparison pilot relaying. The goal is to verify the ability of the entire two-terminal pilot protection scheme to protect for line Faults, and to avoid over-tripping for Faults external to the transmission line zone of protection bounded by the current transformer locations.

Figure A-1



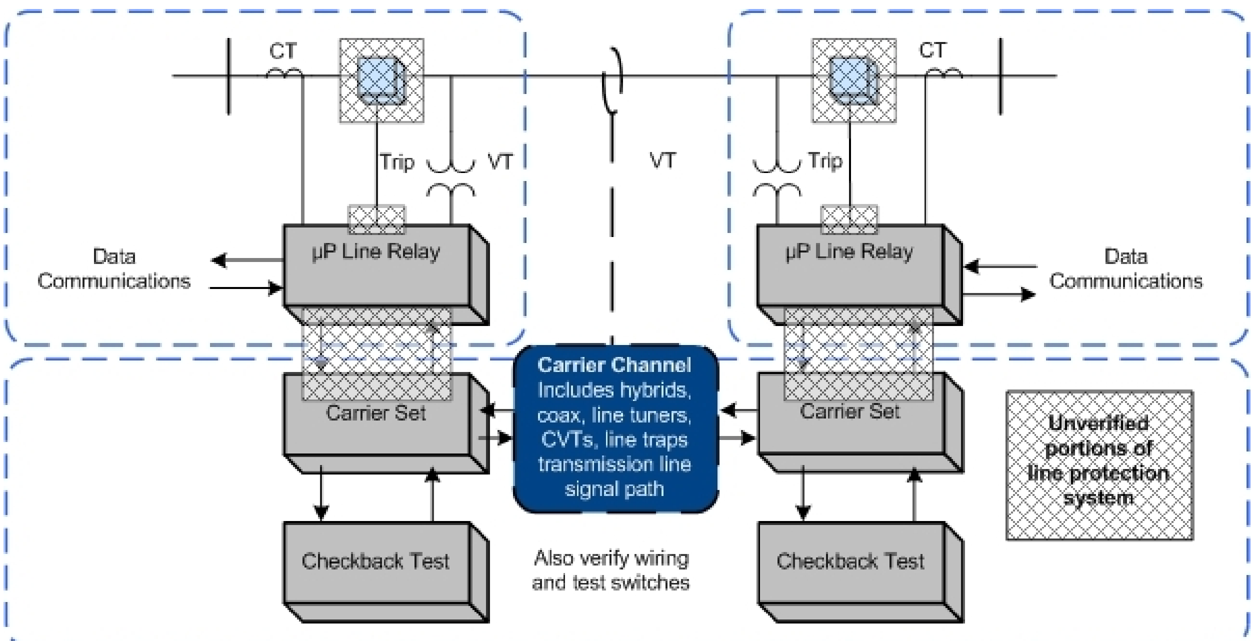
In this example (Figure A1), verification takes advantage of the self-monitoring features of microprocessor multifunction line relays at each end of the line. For each of the line relays themselves, the example assumes that the user has the following arrangements in place:

1. The relay has a data communications port that can be accessed from remote locations.
2. The relay has internal self-monitoring programs and functions that report failures of internal electronics, via communications messages or alarm contacts to SCADA.
3. The relays report loss of dc power, and the relays themselves or external monitors report the state of the dc battery supply.
4. The CT and PT inputs to the relays are used for continuous calculation of metered values of volts, amperes, plus Watts and VARs on the line. These metered values are reported by data communications. For maintenance, the user elects to compare these readings to those of other relays, meters, or DFRs. The other readings may be from redundant relaying or measurement systems or they may be derived from values in other protection zones. Comparison with other such readings to within required relaying accuracy verifies voltage & current sensing devices, wiring, and analog signal input processing of the relays. One effective way to do this is to utilize the relay metered values directly in SCADA, where they can be compared with other references or state estimator values.

5. Breaker status indication from auxiliary contacts is verified in the same way as in (2). Status indications must be consistent with the flow or absence of current.
6. Continuity of the breaker trip circuit from dc bus through the trip coil is monitored by the relay and reported via communications.
7. Correct operation of the on-off carrier channel is also critical to security of the Protection System, so each carrier set has a connected or integrated automatic checkback test unit. The automatic checkback test runs several times a day. Newer carrier sets with integrated checkback testing check for received signal level and report abnormal channel attenuation or noise, even if the problem is not severe enough to completely disable the channel.

These monitoring activities plus the check-back test comprise automatic verification of all the Protection System elements that experience tells us are the most prone to fail. But, does this comprise a complete verification?

Figure A-2



The dotted boxes of Figure A-2 show the sections of verification defined by the monitoring and verification practices just listed. These sections are not completely overlapping, and the shaded regions show elements that are not verified:

1. The continuity of trip coils is verified, but no means is provided for validating the ability of the circuit breaker to trip if the trip coil should be energized.

2. Within each line relay, all the microprocessors that participate in the trip decision have been verified by internal monitoring. However, the trip circuit is actually energized by the contacts of a small telephone-type "ice cube" relay within the line protective relay. The microprocessor energizes the coil of this ice cube relay through its output data port and a transistor driver circuit. There is no monitoring of the output port, driver circuit, ice cube relay, or contacts of that relay. These components are critical for tripping the circuit breaker for a Fault.
3. The check-back test of the carrier channel does not verify the connections between the relaying microprocessor internal decision programs and the carrier transmitter keying circuit or the carrier receiver output state. These connections include microprocessor I/O ports, electronic driver circuits, wiring, and sometimes telephone-type auxiliary relays.
4. The correct states of breaker and disconnect switch auxiliary contacts are monitored, but this does not confirm that the state change indication is correct when the breaker or switch opens.

A practical solution for (1) and (2) is to observe actual breaker tripping, with a specified maximum time interval between trip tests. Clearing of naturally-occurring Faults are demonstrations of operation that reset the time interval clock for testing of each breaker tripped in this way. If Faults do not occur, manual tripping of the breaker through the relay trip output via data communications to the relay microprocessor meets the requirement for periodic testing.

PRC-005-4~~X~~ does not address breaker maintenance, and its Protection System test requirements can be met by energizing the trip circuit in a test mode (breaker disconnected) through the relay microprocessor. This can be done via a front-panel button command to the relay logic, or application of a simulated Fault with a relay test set. However, utilities have found that breakers often show problems during Protection System tests. It is recommended that Protection System verification include periodic testing of the actual tripping of connected circuit breakers.

Testing of the relay-carrier set interface in (3) requires that each relay key its transmitter, and that the other relay demonstrate reception of that blocking carrier. This can be observed from relay or DFR records during naturally occurring Faults, or by a manual test. If the checkback test sequence were incorporated in the relay logic, the carrier sets and carrier channel are then included in the overlapping segments monitored by the two relays, and the monitoring gap is completely eliminated.

Appendix B

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Violation Risk Factor and Violation Severity Level Justifications

Project 2007-17.3 PRC-005-4

Protection System, Automatic Reclosing, and Sudden Pressure Relaying Maintenance

Violation Risk Factor and Violation Severity Level Justifications

This document provides the drafting team's justification for assignment of violation risk factors (VRFs) and violation severity levels (VSLs) for each requirement in PRC-005-4 - Protection System, Automatic Reclosing, and Sudden Pressure Relaying Maintenance.

Each primary requirement is assigned a VRF and a set of one or more VSLs. These elements support the determination of an initial value range for the Base Penalty Amount regarding violations of requirements in FERC-approved Reliability Standards, as defined in the ERO Sanction Guidelines.

The Protection System Maintenance and Testing Standard Drafting Team applied the following NERC criteria and FERC Guidelines when proposing VRFs and VSLs for the requirements under this project:

NERC Criteria – VRFs

High Risk Requirement

A requirement that, if violated, could directly cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures, or could place the bulk electric system at an unacceptable risk of instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures, or could place the bulk electric system at an unacceptable risk of instability, separation, or cascading failures, or could hinder restoration to a normal condition.

Medium Risk Requirement

A requirement that, if violated, could directly affect the electrical state or the capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system. However, violation of a medium risk requirement is unlikely to lead to bulk electric system instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system. However, violation of a medium risk requirement is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to bulk electric system instability, separation, or cascading failures, nor to hinder restoration to a normal condition.

Lower Risk Requirement

A requirement that is administrative in nature and a requirement that, if violated, would not be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system; or, a requirement that is administrative in nature and a requirement in a planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system. A planning requirement that is administrative in nature.

FERC VRF Guidelines

Guideline (1) — Consistency with the Conclusions of the Final Blackout Report

The Commission seeks to ensure that VRFs assigned to Requirements of Reliability Standards in these identified areas appropriately reflect their historical critical impact on the reliability of the Bulk-Power System.

In the VSL Order, FERC listed critical areas (from the Final Blackout Report) where violations could severely affect the reliability of the Bulk-Power System:

Emergency operations

Vegetation management

Operator personnel training

Protection systems and their coordination

Operating tools and backup facilities

Reactive power and voltage control

System modeling and data exchange

Communication protocol and facilities

Requirements to determine equipment ratings

Synchronized data recorders

Clearer criteria for operationally critical facilities

Appropriate use of transmission loading relief

Guideline (2) — Consistency within a Reliability Standard

The Commission expects a rational connection between the sub-Requirement VRF assignments and the main Requirement VRF assignment.

Guideline (3) — Consistency among Reliability Standards

The Commission expects the assignment of VRFs corresponding to Requirements that address similar reliability goals in different Reliability Standards would be treated comparably.

Guideline (4) — Consistency with NERC's Definition of the VRF Level

Guideline (4) was developed to evaluate whether the assignment of a particular VRF level conforms to NERC's definition of that risk level.

Guideline (5) — Treatment of Requirements that Co-mingle More Than One Obligation

Where a single Requirement co-mingles a higher risk reliability objective and a lesser risk reliability objective, the VRF assignment for such Requirements must not be watered down to reflect the lower risk level associated with the less important objective of the Reliability Standard.

The following discussion addresses how the SDT considered FERC's VRF Guidelines 2 through 5. The team did not address Guideline 1 directly because of an apparent conflict between Guidelines 1 and 4. Whereas Guideline 1 identifies a list of topics that encompass nearly all topics within NERC's Reliability Standards and implies that these requirements should be assigned a "High" VRF, Guideline 4 directs assignment of VRFs based on the impact of a specific requirement to the reliability of the system. The SDT believes that Guideline 4 is reflective of the intent of VRFs in the first instance and therefore concentrated its approach on the reliability impact of the requirements.

PRC-005-4 Protection System, Automatic Reclosing and Sudden Pressure Relaying Maintenance is a revision of PRC-005-3 Protection System and Automatic Reclosing Maintenance with the stated purpose: To document and implement programs for the maintenance of all Protection Systems, Automatic Reclosing, and Sudden Pressure Relaying affecting the reliability of the Bulk Electric System (BES) so that they are kept in working order.

PRC-005-4 has five (5) requirements that address the inclusion of Sudden Pressure Relaying. A Table of minimum maintenance activities and maximum maintenance intervals for Sudden Pressure Relaying has been added to PRC-005-3 to address FERC's directives from Order 758. The revised standard requires that entities develop an appropriate Protection System Maintenance Program (PSMP), that they implement their PSMP, and that, in the event they are unable to restore Sudden Pressure Relaying Components to proper working order while performing maintenance, they initiate the follow-up activities necessary to resolve those maintenance issues.

The requirements of PRC-005-4 map one-to-one with the requirements of PRC-005-3. The drafting team did not revise the VRFs for the requirements of PRC-005-3.

PRC-005-4 Requirements R1 and R2 are related to developing and documenting a Protection System Maintenance Program. The Standard Drafting Team determined that the assignment of a VRF of Medium was consistent with the NERC criteria that violations of these requirements could directly affect the electrical state or the capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system but are unlikely to lead to bulk electric system instability, separation, or cascading failures. Additionally, a review of the body of existing NERC Standards with approved VRFs revealed that requirements with similar reliability objectives in other standards are largely assigned a VRF of Medium.

PRC-005-4 Requirements R3 and R4 are related to implementation of the Protection System Maintenance Program. The SDT determined that the assignment of a VRF of High was consistent with the NERC criteria that that violation of these requirements could directly cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures, or could place the bulk electric system at an unacceptable risk of instability, separation, or cascading failures. Additionally, a review of the body of existing NERC Standards with approved VRFs revealed that requirements with similar reliability objectives in other standards are assigned a VRF of High.

PRC-005-4 Requirement R5 relates to the initiation of resolution of unresolved maintenance issues, which describe situations where an entity was unable to restore a Component to proper working order during the performance of the maintenance activity. The Standard Drafting Team determined that the assignment of a VRF of Medium was consistent with the NERC criteria that violation of this requirements could directly affect the electrical state or the capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system but are unlikely to lead to bulk electric system instability, separation, or cascading failures. Additionally, a review of the body of existing NERC Standards with approved VRFs revealed that requirements with similar reliability objectives in other standards are largely assigned a VRF of Medium.

NERC Criteria - VSLs

VSLs define the degree to which compliance with a requirement was not achieved. Each requirement must have at least one VSL. While it is preferable to have four VSLs for each requirement, some requirements do not have multiple “degrees” of noncompliant performance and may have only one, two, or three VSLs.

VSLs should be based on the guidelines shown in the table below:

Lower	Moderate	High	Severe
Missing a minor element (or a small percentage) of the required performance The performance or product measured has significant value as it almost meets the full intent of the requirement.	Missing at least one significant element (or a moderate percentage) of the required performance. The performance or product measured still has significant value in meeting the intent of the requirement.	Missing more than one significant element (or is missing a high percentage) of the required performance or is missing a single vital Component. The performance or product has limited value in meeting the intent of the requirement.	Missing most or all of the significant elements (or a significant percentage) of the required performance. The performance measured does not meet the intent of the requirement or the product delivered cannot be used in meeting the intent of the requirement.

FERC Order on VSLs

In its June 19, 2008 Order on VSLs, FERC indicated it would use the following four guidelines for determining whether to approve VSLs:

Guideline 1: VSL Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance

- Compare the VSLs to any prior Levels of Non-compliance and avoid significant changes that may encourage a lower level of compliance than was required when Levels of Non-compliance were used.

Guideline 2: VSL Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties

- Guideline 2a: A violation of a "binary" type requirement must be a "Severe" VSL.
- Guideline 2b: Do not use ambiguous terms such as "minor" and "significant" to describe noncompliant performance.

Guideline 3: VSL Assignment Should Be Consistent with the Corresponding Requirement

- VSLs should not expand on what is required in the requirement.

Guideline 4: VSL Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations

- . . . unless otherwise stated in the requirement, each instance of non-compliance with a requirement is a separate violation. Section 4 of the Sanction Guidelines states that assessing penalties on a per violation per day basis is the "default" for penalty calculations.

VRF and VSL Justifications

VRF and VSL Justifications – PRC-005-4, R1	
Proposed VRF	**Medium**
NERC VRF Discussion	Failure to establish a Protection System Maintenance Program (PSMP) for Protection Systems designed to provide protection for BES Element(s) could directly affect the electrical state or the capability of the bulk power system. However, violation of this requirement is unlikely to lead to bulk power system instability, separation, or cascading failures. The applicable entities are always responsible for maintaining the reliability of the bulk power system regardless of the situation. This VRF emphasizes the risk to system performance that results from mal-performing Protection System Components. Failure to establish a Protection System Maintenance Program (PSMP) for Protection Systems will not, by itself, lead to instability, separation, or cascading failures. Thus, the requirement meets NERC's criteria for a Medium VRF.
FERC VRF G1 Discussion	Guideline 1- Consistency w/ Blackout Report: N/A
FERC VRF G2 Discussion	Guideline 2- Consistency within a Reliability Standard: The requirement has no sub-requirements so only one VRF was assigned. The requirement utilizes Parts to identify the items to be included within a Protection System Maintenance Program. The VRF for this requirement is consistent with others in the standard with regard to relative risk; therefore, there is no conflict.
FERC VRF G3 Discussion	Guideline 3- Consistency among Reliability Standards: The SDT has determined that there is no consistency among existing approved Standards relative to requirements of this nature. The SDT has assigned a MEDIUM VRF, which is consistent with recent FERC guidance on FAC-008-3 Requirement R2 and FAC-013-2 Requirement R1, which are similar in nature to PRC-005-4 Requirement R1.

VRF and VSL Justifications – PRC-005-4, R1			
Proposed VRF	**Medium**		
FERC VRF G4 Discussion	Guideline 4- Consistency with NERC Definitions of VRFs: Failure to establish a Protection System Maintenance Program (PSMP) for Protection Systems designed to provide protection for BES Element(s) could directly affect the electrical state or the capability of the bulk power system. However, violation of this requirement is unlikely to lead to bulk power system instability, separation, or cascading failures. The applicable entities are always responsible for maintaining the reliability of the bulk power system regardless of the situation. This VRF emphasizes the risk to system performance that results from mal-performing Protection System Components. Failure to establish a Protection System Maintenance Program (PSMP) for Protection Systems will not, by itself, lead to instability, separation, or cascading failures. Thus, the requirement meets NERC's criteria for a Medium VRF.		
FERC VRF G5 Discussion	Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation: This requirement establishes a single risk-level, and the assigned VRF is consistent with that risk level.		
Proposed VSL – PRC-005-4, R1			
Lower	**Moderate**	**High**	**Severe**
The entity's PSMP failed to specify whether one Component Type is being addressed by time-based or performance-based maintenance, or a combination of both. (Part 1.1)	The entity's PSMP failed to specify whether two Component Types are being addressed by time-based or performance-based maintenance, or a combination of both. (Part 1.1)	The entity's PSMP failed to specify whether three Component Types are being addressed by time-based or performance-based maintenance, or a combination of both. (Part 1.1). OR	The entity failed to establish a PSMP. OR The entity's PSMP failed to specify whether four or more Component Types are being addressed by time-based or performance-based maintenance, or a combination of both. (Part 1.1).

Proposed VSL – PRC-005-4, R1			
Lower	**Moderate**	**High**	**Severe**
		The entity's PSMP failed to include the applicable monitoring attributes applied to each Component Type consistent with the maintenance intervals specified in Tables 1-1 through 1-5, Table 2, Table 3, Table 4-1 through 4-2, and Table 5where monitoring is used to extend the maintenance intervals beyond those specified for unmonitored Components. (Part 1.2).	OR The entity's PSMP failed to include applicable station batteries in a time-based program (Part 1.1)

VRF and VSL Justifications – PRC-005-4, R1	
NERC VSL Guidelines	Meets NERC's VSL Guidelines—There is an incremental aspect to the violation and the VSLs follow the guidelines for incremental violations.
FERC VSL G1 VSL Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	This VSL is consistent with the current VSLs associated with the existing requirements of the standards being replaced by this proposed standard.
FERC VSL G2 VSL Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single VSL Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: VSL Assignments that Contain Ambiguous Language	Guideline 2a: N/A Guideline 2b: The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.

VRF and VSL Justifications – PRC-005-4, R1	
FERC VSL G3 VSL Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses similar terminology to that used in the associated requirement, and is therefore consistent with the requirement.
FERC VSL G4 VSL Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The VSL is based on a single violation and not cumulative violations.

VRF and VSL Justifications – PRC-005-4, R2	
Proposed VRF	**Medium**
NERC VRF Discussion	Failure to properly establish a performance-based Protection System Maintenance Program (PSMP) for Protection Systems designed to provide protection for BES Element(s) could directly affect the electrical state or the capability of the bulk power system. However, violation of this requirement is unlikely to lead to bulk power system instability, separation, or cascading failures. The applicable entities are always responsible for maintaining the reliability of the bulk power system regardless of the situation. This VRF emphasizes the risk to system performance that results from mal-performing Protection System Components. Failure to properly establish a performance-based Protection System Maintenance Program (PSMP) for Protection Systems will not, by itself, lead to instability, separation, or cascading failures. Thus, the requirement meets NERC's criteria for a Medium VRF.
FERC VRF G1 Discussion	Guideline 1- Consistency w/ Blackout Report: N/A
FERC VRF G2 Discussion	Guideline 2- Consistency within a Reliability Standard: The requirement has no subpart(s); therefore, only one VRF was assigned and no conflict(s) exist.
FERC VRF G3 Discussion	Guideline 3- Consistency among Reliability Standards: The SDT has determined that there is no consistency among existing approved Standards relative to requirements of this nature. The SDT has assigned a MEDIUM VRF, which is consistent with recent FERC guidance on FAC-008-3 Requirement R2 and FAC-013-2 Requirement R1, which are similar in nature to PRC-005-4 Requirement R1.
FERC VRF G4 Discussion	Guideline 4- Consistency with NERC Definitions of VRFs: Failure to properly establish a performance-based Protection System Maintenance Program (PSMP) for.

VRF and VSL Justifications – PRC-005-4, R2	
Proposed VRF	**Medium**
	Protection Systems designed to provide protection for BES Element(s) could directly affect the electrical state or the capability of the bulk power system. However, violation of this requirement is unlikely to lead to bulk power system instability, separation, or cascading failures. The applicable entities are always responsible for maintaining the reliability of the bulk power system regardless of the situation. This VRF emphasizes the risk to system performance that results from mal-performing Protection System Components. Failure to properly establish a performance-based Protection System Maintenance Program (PSMP) for Protection Systems will not, by itself, lead to instability, separation, or cascading failures. Thus, the requirement meets NERC's criteria for a Medium VRF.
FERC VRF G5 Discussion	Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation: This requirement establishes a single risk-level, and the assigned VRF is consistent with that risk level.

Proposed VSL – PRC-005-4, R2			
Lower	**Moderate**	**High**	**Severe**
The entity uses performance-based maintenance intervals in its PSMP but failed to reduce Countable Events to no more than 4% within three years.	N/A	The entity uses performance-based maintenance intervals in its PSMP but failed to reduce Countable Events to no more than 4% within four years.	The entity uses performance-based maintenance intervals in its PSMP but: 1) Failed to establish the technical justification described within Requirement R2 for the initial use of the performance-based PSMP

Proposed VSL – PRC-005-4, R2			
Lower	Moderate	High	Severe
			OR 2) Failed to reduce countable events to no more than 4% within five years OR 3) Maintained a Segment with less than 60 Components OR 4) Failed to: • Annually update the list of Components, OR • Annually perform maintenance on the greater of 5% of the Segment population or 3 Components, OR • Annually analyze the program activities and results for each Segment.

VRF and VSL Justifications – PRC-005-4, R2	
NERC VSL Guidelines	Meets NERC's VSL Guidelines—There is an incremental aspect to the violation and the VSLs follow the guidelines for incremental violations.
FERC VSL G1 VSL Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	This VSL is consistent with the current VSLs associated with the existing requirements of the standards being replaced by this proposed standard.
FERC VSL G2 VSL Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single VSL Assignment Category for "Binary" Requirements Is Not Consistent	Guideline 2a: N/A Guideline 2b: The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.

VRF and VSL Justifications – PRC-005-4, R2	
Guideline 2b: VSL Assignments that Contain Ambiguous Language	
FERC VSL G3 VSL Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses similar terminology to that used in the associated requirement, and is therefore consistent with the requirement.
FERC VSL G4 VSL Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The VSL is based on a single violation and not cumulative violations.

VRF and VSL Justifications – PRC-005-4, R3	
Proposed VRF	**High**
NERC VRF Discussion	Failure to implement and follow its Protection System Maintenance Program (PSMP) could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures, or could place the bulk electric system at an unacceptable risk of instability, separation, or cascading failures, or could hinder restoration to a normal condition. Thus, this requirement meets the criteria for a High VRF.
FERC VRF G1 Discussion	Guideline 1- Consistency w/ Blackout Report: N/A
FERC VRF G2 Discussion	Guideline 2- Consistency within a Reliability Standard: The requirement has no subpart(s); therefore, only one VRF was assigned and no conflict(s) exist.
FERC VRF G3 Discussion	Guideline 3- Consistency among Reliability Standards: The only Reliability Standards with similar goals are those being replaced by this standard, and the High VRF assignment for this requirement is consistent with the assigned VRFs for companion requirements in those existing standards.
FERC VRF G4 Discussion	Guideline 4- Consistency with NERC Definitions of VRFs: Failure to implement and follow its Protection System Maintenance Program (PSMP) could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures, or could place the bulk electric system at an unacceptable risk of instability, separation, or cascading failures, or could hinder restoration to a normal condition. Thus, this requirement meets the criteria for a High VRF.
FERC VRF G5 Discussion	Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation: This requirement establishes a single risk-level, and the assigned VRF is consistent with that risk level.

Proposed VSL – PRC-005-4, R3			
Lower	**Moderate**	**High**	**Severe**
For Components included within a time-based maintenance program, the entity failed to maintain 5% or less of the total Components included within a specific Component Type, in accordance with the minimum maintenance activities and maximum maintenance intervals prescribed within Tables 1-1 through 1-5, Table 2, Table 3, Table 4-1 through 4-2, and Table 5.	For Components included within a time-based maintenance program, the entity failed to maintain more than 5% but 10% or less of the total Components included within a specific Component Type, in accordance with the minimum maintenance activities and maximum maintenance intervals prescribed within Tables 1-1 through 1-5, Table 2, Table 3, Table 4-1 through 4-2, and Table 5.	For Components included within a time-based maintenance program, the entity failed to maintain more than 10% but 15% or less of the total Components included within a specific Component Type, in accordance with the minimum maintenance activities and maximum maintenance intervals prescribed within Tables 1-1 through 1-5, Table 2, Table 3, Table 4-1 through 4-2, and Table 5.	For Components included within a time-based maintenance program, the entity failed to maintain more than 15% of the total Components included within a specific Component Type, in accordance with the minimum maintenance activities and maximum maintenance intervals prescribed within Tables 1-1 through 1-5, Table 2, Table 3, Table 4-1 through 4-2, and Table 5.

VRF and VSL Justifications – PRC-005-4, R3	
NERC VSL Guidelines	Meets NERC's VSL Guidelines—There is an incremental aspect to the violation and the VSLs follow the guidelines for incremental violations.
FERC VSL G1 VSL Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	This VSL is consistent with the current VSLs associated with the existing requirements of the standards being replaced by this proposed standard.
FERC VSL G2 VSL Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single VSL Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: VSL Assignments that Contain Ambiguous Language	Guideline 2a: N/A Guideline 2b: The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.

VRF and VSL Justifications – PRC-005-4, R3	
FERC VSL G3 VSL Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses similar terminology to that used in the associated requirement, and is therefore consistent with the requirement.
FERC VSL G4 VSL Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The VSL is based on a single violation and not cumulative violations.

VRF and VSL Justifications – PRC-005-4, R4	
Proposed VRF	**High**
NERC VRF Discussion	Failure to implement and follow its Protection System Maintenance Program (PSMP) could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures, or could place the bulk electric system at an unacceptable risk of instability, separation, or cascading failures, or could hinder restoration to a normal condition. Thus, this requirement meets the criteria for a High VRF.
FERC VRF G1 Discussion	Guideline 1- Consistency w/ Blackout Report: N/A
FERC VRF G2 Discussion	Guideline 2- Consistency within a Reliability Standard: The requirement has no subpart(s); therefore, only one VRF was assigned and no conflict(s) exist.
FERC VRF G3 Discussion	Guideline 3- Consistency among Reliability Standards: The only Reliability Standards with similar goals are those being replaced by this standard, and the High VRF assignment for this requirement is consistent with the assigned VRFs for companion requirements in those existing standards.
FERC VRF G4 Discussion	Guideline 4- Consistency with NERC Definitions of VRFs: Failure to implement and follow its Protection System Maintenance Program (PSMP) could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures, or could place the bulk electric system at an unacceptable risk of instability, separation, or cascading failures, or could hinder restoration to a normal condition. Thus, this requirement meets the criteria for a High VRF.
FERC VRF G5 Discussion	Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation: This requirement establishes a single risk-level, and the assigned VRF is consistent with that risk level.

Proposed VSL – PRC-005-4, R4			
Lower	**Moderate**	**High**	**Severe**
For Components included within a performance-based maintenance program, the entity failed to maintain 5% or less of the annual scheduled maintenance for a specific Component Type in accordance with their performance-based PSMP.	For Components included within a performance-based maintenance program, the entity failed to maintain more than 5% but 10% or less of the annual scheduled maintenance for a specific Component Type in accordance with their performance-based PSMP.	For Components included within a performance-based maintenance program, the entity failed to maintain more than 10% but 15% or less of the annual scheduled maintenance for a specific Component Type in accordance with their performance-based PSMP.	For Components included within a performance-based maintenance program, the entity failed to maintain more than 15% of the annual scheduled maintenance for a specific Component Type in accordance with their performance-based PSMP.

VRF and VSL Justifications – PRC-005-4, R4	
NERC VSL Guidelines	Meets NERC's VSL Guidelines—There is an incremental aspect to the violation and the VSLs follow the guidelines for incremental violations.
FERC VSL G1 VSL Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	This VSL is consistent with the current VSLs associated with the existing requirements of the standards being replaced by this proposed standard.
FERC VSL G2 VSL Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single VSL Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: VSL Assignments that Contain Ambiguous Language	Guideline 2a: N/A Guideline 2b: The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.

VRF and VSL Justifications – PRC-005-4, R4	
FERC VSL G3 VSL Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses similar terminology to that used in the associated requirement, and is therefore consistent with the requirement.
FERC VSL G4 VSL Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The VSL is based on a single violation and not cumulative violations.

VRF and VSL Justifications – PRC-005-4, R5	
Proposed VRF	**Medium**
NERC VRF Discussion	Failure to initiate resolution of an unresolved maintenance issue for a Protection System Component could directly affect the electrical state or the capability of the bulk power system. However, violation of this requirement is unlikely to lead to bulk power system instability, separation, or cascading failures. The applicable entities are always responsible for maintaining the reliability of the bulk power system regardless of the situation. This VRF emphasizes the risk to system performance that results from mal-performing Protection System Components. Failure to initiate resolution of an unresolved maintenance issue for a Protection System Component will not, by itself, lead to instability, separation, or cascading failures. Thus, the requirement meets NERC's criteria for a Medium VRF.
FERC VRF G1 Discussion	Guideline 1- Consistency w/ Blackout Report: N/A
FERC VRF G2 Discussion	Guideline 2- Consistency within a Reliability Standard: The requirement has no subpart(s); therefore, only one VRF was assigned and no conflict(s) exist.
FERC VRF G3 Discussion	Guideline 3- Consistency among Reliability Standards: The only requirement within approved Standards, PRC-004-2a Requirements R1 and R2 contain a similar requirement and is assigned a HIGH VRF. However, these requirements contain several subparts, and the VRF must address the most egregious risk related to these subparts, and a comparison to these requirements may be irrelevant. PRC-022-1 Requirement R1.5 contains only a similar requirement, and is assigned a MEDIUM VRF. FAC-003-2 Requirement R5 contains only a similar requirement, and is assigned a MEDIUM VRF.
FERC VRF G4 Discussion	Guideline 4- Consistency with NERC Definitions of VRFs: Failure to initiate resolution of an unresolved maintenance issue for a Protection System Component could directly affect the electrical state or the capability of the bulk power system.

VRF and VSL Justifications – PRC-005-4, R5			
Proposed VRF	**Medium**		
	However, violation of this requirement is unlikely to lead to bulk power system instability, separation, or cascading failures. The applicable entities are always responsible for maintaining the reliability of the bulk power system regardless of the situation. This VRF emphasizes the risk to system performance that results from mal-performing Protection System Components. Failure to initiate resolution of an unresolved maintenance issue for a Protection System Component will not, by itself, lead to instability, separation, or cascading failures. Thus, the requirement meets NERC's criteria for a Medium VRF.		
FERC VRF G5 Discussion	Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation: This requirement establishes a single risk-level, and the assigned VRF is consistent with that risk level.		
Proposed VSL – PRC-005-4, R5			
Lower	**Moderate**	**High**	**Severe**
The entity failed to undertake efforts to correct 5 or fewer identified Unresolved Maintenance Issues.	The entity failed to undertake efforts to correct greater than 5, but less than or equal to 10 identified Unresolved Maintenance Issues.	The entity failed to undertake efforts to correct greater than 10, but less than or equal to 15 identified Unresolved Maintenance Issues.	The entity failed to undertake efforts to correct greater than 15 identified Unresolved Maintenance Issues.

VRF and VSL Justifications – PRC-005X, R5	
NERC VSL Guidelines	Meets NERC's VSL Guidelines—There is an incremental aspect to the violation and the VSLs follow the guidelines for incremental violations.
FERC VSL G1 VSL Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The Requirement in PRC-005-4 is identical to that in PRC-005-3, which has identical VSLs.
FERC VSL G2 VSL Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single VSL Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: VSL Assignments that Contain Ambiguous Language	Guideline 2a: N/A Guideline 2b: The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.

VRF and VSL Justifications – PRC-005-4, R5	
FERC VSL G3 VSL Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses similar terminology to that used in the associated requirement, and is therefore consistent with the requirement.
FERC VSL G4 VSL Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The VSL is based on a single violation and not cumulative violations.

Standards Announcement

Project 2007-17.3 (PRC-005-X) Protection System Maintenance and Testing - Phase 3 (Sudden Pressure Relays)

Final Ballot Now Open through October 29, 2014

Now Available

A final ballot for **PRC-005-4 - Protection System, Automatic Reclosing, and Sudden Pressure Relaying Maintenance** is open through **8 p.m. Eastern Wednesday, October 29, 2014.**

This standard was previously titled PRC-005-X and has been updated to PRC-005-4 due to final ballot. Project 2014-01 Standards Applicability for Dispersed Generation Resources will be updated from PRC-005-X(X) to PRC-005-4(i). For information regarding the NERC numbering system, click here.

Background information for this project can be found on the project page.

Instructions for Balloting

In the final ballot, votes are counted by exception. Only members of the ballot pool may cast a ballot; all ballot pool members may change their previously cast votes. A ballot pool member who failed to cast a vote during the last ballot window may cast a vote in the final ballot window. If a ballot pool member cast a vote in the previous ballot and does not participate in the final ballot, that member's vote will be carried over in the final ballot.

Members of the ballot pool associated with this project may log in and submit their vote for the standard by clicking here.

Next Steps

The voting results for the standard will be posted and announced after the ballot window closes. If approved, it will be submitted to the Board of Trustees for adoption and then filed with the appropriate regulatory authorities**.**

For information on the **Standards Development Process**, please refer to the Standard Processes Manual.

For more information or assistance, please contact Jordan Mallory,
Standards Developer, or at 404-446-9733.

North American Electric Reliability Corporation
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Atlanta, GA 30326
404-446-2560 | www.nerc.com

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Standards Announcement

Project 2007-17.3 (PRC-005-4) Protection System Maintenance and Testing – Phase 3 (Sudden Pressure Relays)

Final Ballot Results

Now Available

A final ballot for **PRC-005-4 - Protection System, Automatic Reclosing, and Sudden Pressure Relaying Maintenance** concluded at **8 p.m. Eastern, Wednesday, October 29, 2014.**

This standard was previously titled PRC-005-X and has been updated to PRC-005-4 due to final ballot. Project 2014-01 Standards Applicability for Dispersed Generation Resources will be updated from PRC-005-X(X) to PRC-005-4(i). For information regarding the NERC numbering system, click here.

The standard achieved a quorum and received sufficient affirmative votes for approval. Voting statistics are listed below, and the Ballot Results page provides a link to the detailed results for the ballot.

Ballot
Quorum /Approval
88.25% / 74.14%

Background information for this project can be found on the project page.

Next Steps

The standard will be submitted to the Board of Trustees for adoption and then filed with the appropriate regulatory authorities.

For more information on the **Standards Development Process**, please refer to the Standard Processes Manual.

For more information or assistance, please contact Jordan Mallory, Standards Developer, or at 404-446-9733.

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Ballot Results	
Ballot Name:	Project 2007-17.3 PSMT - Sudden Pressure Relays PRC-005-4
Ballot Period:	10/20/2014 - 10/29/2014
Ballot Type:	Final
Total # Votes:	338
Total Ballot Pool:	383
Quorum:	**88.25 % The Quorum has been reached**
Weighted Segment Vote:	74.14 %
Ballot Results:	**A quorum was reached and there were sufficient affirmative votes for approval.**

Summary of Ballot Results

Segment	Ballot Pool	Segment Weight	Affirmative # Votes	Affirmative Fraction	Negative # Votes	Negative Fraction	Negative Vote without a Comment	Abstain	No Vote
1 - Segment 1	105	1	60	0.759	19	0.241	0	12	14
2 - Segment 2	9	0.5	5	0.5	0	0	0	4	0
3 - Segment 3	82	1	50	0.704	21	0.296	0	7	4
4 - Segment 4	28	1	13	0.565	10	0.435	0	1	4
5 - Segment 5	88	1	43	0.652	23	0.348	0	9	13
6 - Segment 6	54	1	28	0.636	16	0.364	0	3	7
7 - Segment 7	2	0.1	0	0	1	0.1	0	0	1
8 - Segment 8	4	0.3	3	0.3	0	0	0	0	1
9 - Segment 9	2	0.2	2	0.2	0	0	0	0	0

10 - Segment 10	9	0.8	8	0.8	0	0	0	0	1
Totals	**383**	**6.9**	**212**	**5.116**	**90**	**1.784**	**0**	**36**	**45**

Individual Ballot Pool Results

Segment	Organization	Member	Ballot	NERC Notes
1	Ameren Services	Eric Scott	Affirmative	
1	American Electric Power	Paul B Johnson	Affirmative	
1	American Transmission Company, LLC	Andrew Z Pusztai	Abstain	
1	Arizona Public Service Co.	Robert Smith		
1	Associated Electric Cooperative, Inc.	John Bussman	Affirmative	
1	ATCO Electric	Glen Sutton	Abstain	
1	Austin Energy	James Armke	Negative	
1	Avista Utilities	Heather Rosentrater	Affirmative	
1	Balancing Authority of Northern California	Kevin Smith	Affirmative	
1	Baltimore Gas & Electric Company	Christopher J Scanlon	Affirmative	
1	BC Hydro and Power Authority	Patricia Robertson	Abstain	
1	Black Hills Corp	Wes Wingen		
1	Bonneville Power Administration	Donald S. Watkins	Affirmative	
1	Bryan Texas Utilities	John C Fontenot	Affirmative	
1	CenterPoint Energy Houston Electric, LLC	John Brockhan	Affirmative	
1	Central Electric Power Cooperative	Michael B Bax	Affirmative	
1	Central Iowa Power Cooperative	Kevin J Lyons	Affirmative	
1	City and County of San Francisco	Lenise Kimes	Abstain	
1	City of Tacoma, Department of Public Utilities, Light Division, dba Tacoma Power	Chang G Choi	Negative	SUPPORTS THIRD PARTY COMMENTS - Keith Morisette, Tacoma Power
1	City of Tallahassee	Daniel S Langston	Negative	
1	Clark Public Utilities	Jack Stamper	Affirmative	
1	Colorado Springs Utilities	Shawna Speer	Negative	SUPPORTS THIRD PARTY COMMENTS
1	Consolidated Edison Co. of New York	Christopher L de Graffenried	Affirmative	
1	CPS Energy	Glenn Pressler	Affirmative	
1	Dairyland Power Coop.	Robert W. Roddy	Affirmative	
1	Dayton Power & Light Co.	Hertzel Shamash	Affirmative	
1	Dominion Virginia Power	Larry Nash	Negative	SUPPORTS THIRD PARTY COMMENTS
1	Duke Energy Carolina	Doug E Hils	Affirmative	
1	Duquesne Light Co.	Hugh R Conley		
1	East Kentucky Power Coop.	Amber Anderson	Affirmative	
1	Empire District Electric Co.	Ralph F Meyer		
1	Encari	Steven E Hamburg		
1	Entergy Transmission	Oliver A Burke	Affirmative	
1	FirstEnergy Corp.	William J Smith	Affirmative	
1	Florida Keys Electric Cooperative Assoc.	Dennis Minton	Affirmative	
1	Florida Power & Light Co.	Mike O'Neil	Affirmative	
1	Gainesville Regional Utilities	Richard Bachmeier	Negative	SUPPORTS THIRD PARTY COMMENTS
1	Georgia Transmission Corporation	Jason Snodgrass	Affirmative	
1	Great River Energy	Gordon Pietsch	Affirmative	
1	Hoosier Energy Rural Electric Cooperative, Inc.	Bob Solomon		
1	Hydro One Networks, Inc.	Muhammed Ali	Affirmative	
1	Hydro-Quebec TransEnergie	Martin Boisvert	Abstain	
1	Idaho Power Company	Molly Devine	Affirmative	

1	International Transmission Company Holdings Corp	Michael Moltane	Affirmative	
1	JDRJC Associates	Jim D Cyrulewski	Affirmative	
1	JEA	Ted E Hobson	Negative	COMMENT RECEIVED
1	Kansas City Power & Light Co.	Daniel Gibson	Affirmative	
1	Keys Energy Services	Stan T Rzad	Negative	
1	Lakeland Electric	Larry E Watt	Negative	SUPPORTS THIRD PARTY COMMENTS
1	Lee County Electric Cooperative	John Chin	Abstain	
1	Lincoln Electric System	Doug Bantam	Affirmative	
1	Long Island Power Authority	Robert Ganley	Negative	SUPPORTS THIRD PARTY COMMENTS
1	Los Angeles Department of Water & Power	faranak sarbaz	Affirmative	COMMENT RECEIVED
1	Lower Colorado River Authority	Martyn Turner	Affirmative	
1	M & A Electric Power Cooperative	William Price	Affirmative	
1	Manitoba Hydro	Jo-Anne M Ross	Negative	COMMENT RECEIVED
1	MidAmerican Energy Co.	Terry Harbour	Affirmative	
1	Minnkota Power Coop. Inc.	Daniel L Inman	Abstain	
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey	Affirmative	
1	National Grid USA	Michael Jones	Affirmative	
1	NB Power Corporation	Alan MacNaughton	Abstain	
1	Nebraska Public Power District	Jamison Cawley	Negative	COMMENT RECEIVED
1	New York Power Authority	Bruce Metruck	Affirmative	
1	Northeast Missouri Electric Power Cooperative	Kevin White	Affirmative	
1	Northeast Utilities	William Temple	Affirmative	
1	Northern Indiana Public Service Co.	Julaine Dyke	Negative	SUPPORTS THIRD PARTY COMMENTS
1	NorthWestern Energy	John Canavan		
1	Ohio Valley Electric Corp.	Scott R Cunningham	Affirmative	
1	Oklahoma Gas and Electric Co.	Terri Pyle	Affirmative	
1	Omaha Public Power District	Doug Peterchuck	Affirmative	
1	Oncor Electric Delivery	Jen Fiegel	Affirmative	
1	Otter Tail Power Company	Daryl Hanson	Affirmative	
1	Pacific Gas and Electric Company	Bangalore Vijayraghavan		
1	Platte River Power Authority	John C. Collins	Affirmative	
1	Portland General Electric Co.	John T Walker	Negative	
1	Potomac Electric Power Co.	David Thorne	Affirmative	
1	PPL Electric Utilities Corp.	Brenda L Truhe	Affirmative	
1	Public Service Company of New Mexico	Laurie Williams	Abstain	
1	Public Service Electric and Gas Co.	Kenneth D. Brown	Negative	SUPPORTS THIRD PARTY COMMENTS
1	Puget Sound Energy, Inc.	Denise M Lietz	Negative	
1	Rochester Gas and Electric Corp.	John C. Allen	Abstain	
1	Sacramento Municipal Utility District	Tim Kelley	Affirmative	
1	Salt River Project	Robert Kondziolka	Negative	COMMENT RECEIVED
1	SaskPower	Wayne Guttormson	Abstain	
1	Seattle City Light	Pawel Krupa	Affirmative	
1	Seminole Electric Cooperative, Inc.	Glenn Spurlock	Negative	
1	Snohomish County PUD No. 1	Long T Duong	Affirmative	
1	South Carolina Electric & Gas Co.	Tom Hanzlik	Affirmative	
1	South Carolina Public Service Authority	Shawn T Abrams	Abstain	
1	Southern California Edison Company	Steven Mavis	Affirmative	
1	Southern Company Services, Inc.	Robert A. Schaffeld	Affirmative	
1	Southern Illinois Power Coop.	William Hutchison		
1	Southwest Transmission Cooperative, Inc.	John Shaver	Affirmative	
1	Sunflower Electric Power Corporation	Noman Lee Williams	Affirmative	
1	Tampa Electric Co.	Beth Young		

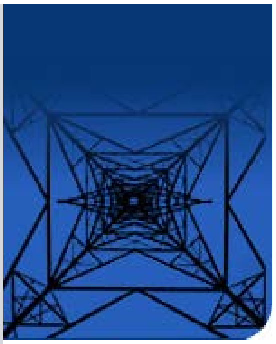
1	Tennessee Valley Authority	Howell D Scott	Affirmative	
1	Tri-State Generation & Transmission Association, Inc.	Tracy Sliman	Affirmative	
1	Tucson Electric Power Co.	John Tolo		
1	U.S. Bureau of Reclamation	Richard T Jackson	Negative	
1	United Illuminating Co.	Jonathan Appelbaum	Affirmative	
1	Vermont Electric Power Company, Inc.	Kim Moulton		
1	Westar Energy	Allen Klassen	Affirmative	
1	Western Area Power Administration	Lloyd A Linke	Affirmative	
1	Wolverine Power Supply Coop., Inc.	Michelle Clements		
1	Xcel Energy, Inc.	Gregory L Pieper		
2	BC Hydro	Venkataramakrishnan Vinnakota	Abstain	
2	California ISO	Rich Vine	Affirmative	
2	Electric Reliability Council of Texas, Inc.	Cheryl Moseley	Abstain	
2	Independent Electricity System Operator	Leonard Kula	Affirmative	
2	ISO New England, Inc.	Matthew F Goldberg	Abstain	
2	MISO	Marie Knox	Abstain	
2	New York Independent System Operator	Gregory Campoli	Affirmative	
2	PJM Interconnection, L.L.C.	stephanie monzon	Affirmative	
2	Southwest Power Pool, Inc.	Charles H. Yeung	Affirmative	
3	AEP	Michael E Deloach	Affirmative	
3	Alabama Power Company	Robert S Moore	Affirmative	
3	Ameren Corp.	David J Jendras	Affirmative	
3	APS	Sarah Kist	Affirmative	
3	Associated Electric Cooperative, Inc.	Todd Bennett	Affirmative	
3	Atlantic City Electric Company	NICOLE BUCKMAN	Affirmative	
3	Avista Corp.	Scott J Kinney	Abstain	
3	BC Hydro and Power Authority	Pat G. Harrington	Abstain	
3	Bonneville Power Administration	Rebecca Berdahl	Affirmative	
3	Central Electric Power Cooperative	Adam M Weber	Affirmative	
3	City of Anaheim Public Utilities Department	Dennis M Schmidt	Abstain	
3	City of Austin dba Austin Energy	Andrew Gallo	Negative	
3	City of Clewiston	Lynne Mila	Negative	
3	City of Farmington	Linda R Jacobson	Abstain	
3	City of Green Cove Springs	Mark Schultz	Negative	
3	City of Redding	Bill Hughes	Affirmative	
3	City of Tallahassee	Bill R Fowler	Negative	
3	Colorado Springs Utilities	Jean Mueller	Negative	
3	ComEd	John Bee	Affirmative	
3	Consolidated Edison Co. of New York	Peter T Yost	Affirmative	
3	Consumers Energy Company	Gerald G Farringer	Affirmative	
3	Cowlitz County PUD	Russell A Noble	Negative	
3	CPS Energy	Jose Escamilla	Affirmative	
3	Delmarva Power & Light Co.	Michael R. Mayer	Affirmative	
3	Dominion Resources, Inc.	Connie B Lowe	Negative	
3	DTE Electric	Kent Kujala	Affirmative	
3	East Kentucky Power Coop.	Patrick Woods	Affirmative	
3	Empire District Electric Co.	Kalem Long		
3	FirstEnergy Corp.	Cindy E Stewart	Affirmative	
3	Florida Keys Electric Cooperative	Tom B Anthony	Affirmative	
3	Florida Municipal Power Agency	Joe McKinney	Negative	
3	Florida Power Corporation	Lee Schuster	Affirmative	
3	Georgia System Operations Corporation	Scott McGough	Affirmative	
3	Great River Energy	Brian Glover	Affirmative	
3	Hydro One Networks, Inc.	Ayesha Sabouba	Affirmative	
3	JEA	Garry Baker	Negative	SUPPORTS THIRD PARTY COMMENTS
3	Kansas City Power & Light Co.	Joshua D Bach	Affirmative	
3	Kissimmee Utility Authority	Gregory D Woessner	Negative	
3	Lakeland Electric	Mace D Hunter	Negative	
3	Lee County Electric Cooperative	David A Hadzima	Abstain	
3	Lincoln Electric System	Jason Fortik	Affirmative	
3	Los Angeles Department of Water & Power	Mike Anctil	Affirmative	
3	Louisville Gas and Electric Co.	Charles A. Freibert	Affirmative	
3	Manitoba Hydro	Greg C. Parent	Negative	COMMENT

				RECEIVED
3	MidAmerican Energy Co.	Thomas C. Mielnik	Affirmative	
3	Modesto Irrigation District	Jack W Savage	Affirmative	
3	Muscatine Power & Water	John S Bos		
3	National Grid USA	Brian E Shanahan	Affirmative	
3	Nebraska Public Power District	Tony Eddleman	Negative	
3	New York Power Authority	David R Rivera	Affirmative	
3	Northern Indiana Public Service Co.	Ramon J Barany	Negative	SUPPORTS THIRD PARTY COMMENTS
3	NW Electric Power Cooperative, Inc.	David McDowell	Affirmative	
3	Ocala Utility Services	Randy Hahn	Negative	
3	Oklahoma Gas and Electric Co.	Donald Hargrove	Affirmative	
3	Omaha Public Power District	Blaine R. Dinwiddie	Affirmative	
3	Orlando Utilities Commission	Ballard K Mutters	Affirmative	
3	Owensboro Municipal Utilities	Thomas T Lyons	Affirmative	
3	Pacific Gas and Electric Company	John H Hagen	Affirmative	
3	Platte River Power Authority	Terry L Baker	Affirmative	
3	PNM Resources	Michael Mertz	Affirmative	
3	Portland General Electric Co.	Thomas G Ward	Abstain	
3	Potomac Electric Power Co.	Mark Yerger	Affirmative	
3	Public Service Electric and Gas Co.	Jeffrey Mueller	Negative	SUPPORTS THIRD PARTY COMMENTS
3	Puget Sound Energy, Inc.	Mariah R Kennedy	Negative	
3	Rutherford EMC	Thomas Haire	Negative	
3	Sacramento Municipal Utility District	James Leigh-Kendall	Affirmative	
3	Salt River Project	John T. Underhill	Negative	SUPPORTS THIRD PARTY COMMENTS
3	Santee Cooper	James M Poston	Negative	
3	Seattle City Light	Dana Wheelock	Affirmative	
3	Seminole Electric Cooperative, Inc.	James R Frauen	Affirmative	
3	Sho-Me Power Electric Cooperative	Jeff L Neas	Affirmative	
3	Snohomish County PUD No. 1	Mark Oens	Affirmative	
3	South Carolina Electric & Gas Co.	Hubert C Young	Abstain	
3	Southern California Edison Company	Lujuanna Medina	Affirmative	
3	Tacoma Power	Marc Donaldson	Negative	
3	Tampa Electric Co.	Ronald L. Donahey		
3	Tennessee Valley Authority	Ian S Grant	Affirmative	
3	Tri-State Generation & Transmission Association, Inc.	Janelle Marriott	Affirmative	
3	Westar Energy	Bo Jones	Affirmative	
3	Wisconsin Electric Power Marketing	James R Keller	Affirmative	
3	Wisconsin Public Service Corp.	Gregory J Le Grave		
3	Xcel Energy, Inc.	Michael Ibold	Affirmative	
4	Alliant Energy Corp. Services, Inc.	Kenneth Goldsmith	Affirmative	
4	Blue Ridge Power Agency	Duane S Dahlquist	Affirmative	
4	City of Austin dba Austin Energy	Reza Ebrahimian	Negative	
4	City of Redding	Nicholas Zettel	Affirmative	
4	City Utilities of Springfield, Missouri	John Allen	Negative	SUPPORTS THIRD PARTY COMMENTS
4	Consumers Energy Company	Tracy Goble	Affirmative	
4	Cowlitz County PUD	Rick Syring	Negative	
4	DTE Electric	Daniel Herring	Affirmative	
4	Flathead Electric Cooperative	Russ Schneider	Abstain	
4	Florida Municipal Power Agency	Frank Gaffney	Negative	COMMENT RECEIVED
4	Fort Pierce Utilities Authority	Cairo Vanegas	Negative	
4	Georgia System Operations Corporation	Guy Andrews	Affirmative	
4	Herb Schrayshuen	Herb Schrayshuen	Affirmative	
4	Illinois Municipal Electric Agency	Bob C. Thomas	Negative	COMMENT RECEIVED
4	Indiana Municipal Power Agency	Jack Alvey	Negative	SUPPORTS THIRD

				PARTY COMMENTS
4	Integrys Energy Group, Inc.	Christopher Plante		
4	Madison Gas and Electric Co.	Joseph DePoorter	Negative	
4	Modesto Irrigation District	Spencer Tacke		
4	Ohio Edison Company	Douglas Hohlbaugh	Affirmative	
4	Oklahoma Municipal Power Authority	Ashley Stringer	Negative	
4	Public Utility District No. 1 of Snohomish County	John D Martinsen	Affirmative	
4	Sacramento Municipal Utility District	Mike Ramirez	Affirmative	
4	Seattle City Light	Hao Li	Affirmative	
4	Seminole Electric Cooperative, Inc.	Steven R Wallace	Affirmative	
4	South Mississippi Electric Power Association	Steve McElhaney		
4	Tacoma Public Utilities	Keith Morisette	Negative	
4	Utility Services, Inc.	Brian Evans-Mongeon	Affirmative	
4	Wisconsin Energy Corp.	Anthony Jankowski		
5	AES Corporation	Leo Bernier	Affirmative	
5	Amerenue	Sam Dwyer	Affirmative	
5	American Electric Power	Thomas Foltz	Affirmative	
5	Arizona Public Service Co.	Scott Takinen	Affirmative	
5	Associated Electric Cooperative, Inc.	Matthew Pacobit	Affirmative	
5	BC Hydro and Power Authority	Clement Ma	Abstain	
5	Boise-Kuna Irrigation District/dba Lucky peak power plant project	Mike D Kukla	Affirmative	
5	Bonneville Power Administration	Francis J. Halpin	Affirmative	
5	Brazos Electric Power Cooperative, Inc.	Shari Heino	Affirmative	
5	Calpine Corporation	Hamid Zakery	Abstain	
5	City and County of San Francisco	Daniel Mason	Abstain	
5	City of Austin dba Austin Energy	Jeanie Doty	Negative	
5	City of Redding	Paul A. Cummings	Affirmative	
5	City of Tallahassee	Karen Webb	Negative	
5	City Water, Light & Power of Springfield	Steve Rose		
5	Cleco Power	Stephanie Huffman	Affirmative	
5	Cogentrix Energy Power Management, LLC	Mike D Hirst		
5	Colorado Springs Utilities	Kaleb Brimhall	Negative	
5	Con Edison Company of New York	Brian O'Boyle	Affirmative	
5	Consumers Energy Company	David C Greyerbiehl	Affirmative	
5	Cowlitz County PUD	Bob Essex	Negative	
5	Dairyland Power Coop.	Tommy Drea		
5	Dominion Resources, Inc.	Mike Garton	Negative	
5	DTE Electric	Mark Stefaniak	Affirmative	
5	Duke Energy	Dale Q Goodwine	Affirmative	
5	Dynegy Inc.	Dan Roethemeyer	Affirmative	
5	E.ON Climate & Renewables North America, LLC	Dana Showalter		
5	East Kentucky Power Coop.	Stephen Ricker	Affirmative	
5	EDP Renewables North America LLC	Heather Bowden		
5	El Paso Electric Company	Gustavo Estrada		
5	Empire District Electric Co.	mike l kidwell		
5	Entergy Services, Inc.	Tracey Stubbs	Affirmative	
5	Exelon Nuclear	Mark F Draper	Affirmative	
5	First Wind	John Robertson	Affirmative	
5	FirstEnergy Solutions	Kenneth Dresner	Affirmative	
5	Florida Municipal Power Agency	David Schumann	Negative	
5	Great River Energy	Preston L Walsh	Affirmative	
5	Hydro-Québec Production	Roger Dufresne	Abstain	
5	Ingleside Cogeneration LP	Michelle R DAntuono	Negative	
5	JEA	John J Babik	Negative	COMMENT RECEIVED
5	Kansas City Power & Light Co.	Brett Holland	Affirmative	
5	Kissimmee Utility Authority	Mike Blough	Negative	
5	Lakeland Electric	James M Howard	Negative	SUPPORTS THIRD PARTY COMMENTS
5	Liberty Electric Power LLC	Daniel Duff	Negative	
5	Lincoln Electric System	Dennis Florom	Affirmative	
				SUPPORTS THIRD

5	Los Angeles Department of Water & Power	Kenneth Silver	Negative	PARTY COMMENTS
5	Lower Colorado River Authority	Dixie Wells	Affirmative	
5	Luminant Generation Company LLC	Rick Terrill	Affirmative	
5	Manitoba Hydro	Chris Mazur	Negative	COMMENT RECEIVED
5	Massachusetts Municipal Wholesale Electric Company	David Gordon	Abstain	
5	Muscatine Power & Water	Mike Avesing	Affirmative	
5	Nebraska Public Power District	Don Schmit	Negative	SUPPORTS THIRD PARTY COMMENTS
5	New York Power Authority	Wayne Sipperly	Affirmative	
5	NextEra Energy	Allen D Schriver	Affirmative	
5	North Carolina Electric Membership Corp.	Jeffrey S Brame	Affirmative	
5	Northern Indiana Public Service Co.	Michael D Melvin	Negative	SUPPORTS THIRD PARTY COMMENTS
5	Oglethorpe Power Corporation	Bernard Johnson		
5	Oklahoma Gas and Electric Co.	Henry L Staples	Affirmative	
5	Omaha Public Power District	Mahmood Z. Safi	Affirmative	
5	Orlando Utilities Commission	Richard K Kinas		
5	Pacific Gas and Electric Company	Alex Chua	Affirmative	
5	Platte River Power Authority	Christopher R Wood	Affirmative	
5	Portland General Electric Co.	Matt E. Jastram	Negative	
5	PPL Generation LLC	Annette M Bannon	Affirmative	
5	PSEG Fossil LLC	Tim Kucey	Negative	SUPPORTS THIRD PARTY COMMENTS
5	Public Utility District No. 1 of Lewis County	Steven Grega	Negative	
5	Public Utility District No. 2 of Grant County, Washington	Michiko Sell	Abstain	
5	Puget Sound Energy, Inc.	Lynda Kupfer	Negative	
5	Sacramento Municipal Utility District	Susan Gill-Zobitz	Affirmative	
5	Salt River Project	William Alkema	Negative	SUPPORTS THIRD PARTY COMMENTS
5	Santee Cooper	Lewis P Pierce	Negative	
5	Seattle City Light	Michael J. Haynes		
5	Snohomish County PUD No. 1	Sam Nietfeld	Affirmative	
5	South Carolina Electric & Gas Co.	Edward Magic	Abstain	
5	South Feather Power Project	Kathryn Zancanella	Abstain	
5	Southern California Edison Company	Denise Yaffe	Affirmative	
5	Southern Company Generation	William D Shultz	Affirmative	
5	Tacoma Power	Chris Mattson	Negative	
5	Tampa Electric Co.	RJames Rocha	Abstain	
5	Tenaska, Inc.	Scott M. Helyer		
5	Tennessee Valley Authority	David Thompson	Affirmative	
5	Tri-State Generation & Transmission Association, Inc.	Mark Stein	Affirmative	
5	U.S. Army Corps of Engineers	Melissa Kurtz		
5	USDI Bureau of Reclamation	Erika Doot	Negative	
5	Westar Energy	Bryan Taggart	Affirmative	
5	Wisconsin Electric Power Co.	Linda Horn	Affirmative	
5	Wisconsin Public Service Corp.	Scott E Johnson		
5	Xcel Energy, Inc.	Mark A Castagneri	Affirmative	
6	AEP Marketing	Edward P. Cox	Abstain	
6	Ameren Missouri	Robert Quinlivan	Affirmative	
6	APS	Randy A. Young	Affirmative	
6	Associated Electric Cooperative, Inc.	Brian Ackermann	Affirmative	
6	Bonneville Power Administration	Brenda S. Anderson	Affirmative	
6	City of Austin dba Austin Energy	Lisa Martin	Negative	
6	City of Redding	Marvin Briggs	Affirmative	
6	Cleco Power LLC	Robert Hirchak	Affirmative	
6	Colorado Springs Utilities	Shannon Fair	Negative	
6	Con Edison Company of New York	David Balban	Affirmative	

6	Constellation Energy Commodities Group	David J Carlson	Affirmative	
6	Dominion Resources, Inc.	Louis S. Slade	Negative	
6	Duke Energy	Greg Cecil		
6	FirstEnergy Solutions	Kevin Querry	Affirmative	
6	Florida Municipal Power Agency	Richard L. Montgomery	Negative	
6	Florida Municipal Power Pool	Thomas Washburn	Negative	
6	Florida Power & Light Co.	Silvia P Mitchell	Affirmative	
6	Kansas City Power & Light Co.	Jessica L Klinghoffer	Affirmative	
6	Lakeland Electric	Paul Shipps	Negative	SUPPORTS THIRD PARTY COMMENTS
6	Lincoln Electric System	Eric Ruskamp	Affirmative	
6	Los Angeles Department of Water & Power	Brad Packer	Affirmative	
6	Lower Colorado River Authority	Michael Shaw	Negative	SUPPORTS THIRD PARTY COMMENTS
6	Luminant Energy	Brenda Hampton		
6	Manitoba Hydro	Blair Mukanik	Negative	COMMENT RECEIVED
6	Modesto Irrigation District	James McFall	Affirmative	
6	New York Power Authority	Shivaz Chopra	Affirmative	
6	Northern California Power Agency	Steve C Hill		
6	Northern Indiana Public Service Co.	Joseph O'Brien	Negative	COMMENT RECEIVED
6	Oglethorpe Power Corporation	Donna Johnson	Negative	SUPPORTS THIRD PARTY COMMENTS
6	Oklahoma Gas and Electric Co.	Jerry Nottnagel	Affirmative	
6	Omaha Public Power District	Douglas Collins		
6	PacifiCorp	Sandra L Shaffer	Affirmative	
6	Platte River Power Authority	Carol Ballantine	Affirmative	
6	Portland General Electric Co.	Shawn P Davis	Negative	
6	Power Generation Services, Inc.	Stephen C Knapp	Affirmative	
6	Powerex Corp.	Gordon Dobson-Mack	Abstain	
6	PPL EnergyPlus LLC	Elizabeth Davis	Affirmative	
6	PSEG Energy Resources & Trade LLC	Peter Dolan	Negative	
6	Public Utility District No. 1 of Chelan County	Hugh A. Owen	Abstain	
6	Sacramento Municipal Utility District	Diane Enderby	Affirmative	
6	Salt River Project	William Abraham	Negative	SUPPORTS THIRD PARTY COMMENTS
6	Santee Cooper	Michael Brown	Negative	
6	Seattle City Light	Dennis Sismaet	Affirmative	
6	Seminole Electric Cooperative, Inc.	Trudy S. Novak	Negative	
6	Snohomish County PUD No. 1	Kenn Backholm	Affirmative	
6	Southern California Edison Company	Joseph T Marone	Affirmative	
6	Southern Company Generation and Energy Marketing	John J. Ciza	Affirmative	
6	Tacoma Public Utilities	Michael C Hill	Negative	
6	Tampa Electric Co.	Benjamin F Smith II		
6	Tennessee Valley Authority	Marjorie S Parsons	Affirmative	
6	Westar Energy	Grant L Wilkerson	Affirmative	
6	Western Area Power Administration - UGP Marketing	Peter H Kinney		
6	Wisconsin Public Service Corp.	David Hathaway		
6	Xcel Energy, Inc.	Peter Colussy	Affirmative	
7	Occidental Chemical	Venona Greaff	Negative	
7	Siemens Energy, Inc.	Frank R. McElvain		
8		David L Kiguel	Affirmative	
8		Roger C Zaklukiewicz	Affirmative	
8	Massachusetts Attorney General	Frederick R Plett	Affirmative	
8	Volkmann Consulting, Inc.	Terry Volkmann		
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson	Affirmative	
9	New York State Public Service Commission	Diane J Barney	Affirmative	
10	Florida Reliability Coordinating Council	Linda C Campbell	Affirmative	



10	Midwest Reliability Organization	Russel Mountjoy	Affirmative	
10	New York State Reliability Council	Alan Adamson	Affirmative	
10	Northeast Power Coordinating Council	Guy V. Zito	Affirmative	
10	ReliabilityFirst	Anthony E Jablonski	Affirmative	
10	SERC Reliability Corporation	Joseph W Spencer	Affirmative	
10	Southwest Power Pool RE	Bob Reynolds		
10	Texas Reliability Entity, Inc.	Karin Schweitzer	Affirmative	
10	Western Electricity Coordinating Council	Steven L. Rueckert	Affirmative	

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Washington Office: 1325 G Street, N.W. : Suite 600 : Washington, DC 20005-3801

Account Log-In/Register

Exhibit I

Standard Drafting Team Roster for Project 2007-17.3

Standard Drafting Team Roster

Project 2007-17.3 Protection System Maintenance and Testing-Phase 3 (Sudden Pressure Relays)

Member	Bio
John Anderson Principal Engineer Xcel Energy, Inc. 1518 Chestnut Avenue N. 2nd Floor Minneapolis MN 55403 Business: (612) 630-4630 john.b.anderson@xcelenergy.com	John Anderson is presently a Principal Engineer with Xcel Energy and is responsible for the development and implementation of the company's power plant electrical distribution system equipment maintenance programs including those for plant protective relay systems, power transformers, circuit breakers and battery systems. He has served in this capacity since 1998. Prior to taking on this fleet wide coordination role, he served for 8 years as an Electrical System Engineer at Xcel Energy's Monticello Nuclear Generating Station with responsibilities including coordination of the plant's protection system testing program. During this time, Mr. Anderson earned a Senior Reactor Operator Certification for the plant. Prior to joining Northern State Power Company in 1990, Mr. Anderson completed the Navy Nuclear Propulsion Officer training program and served as a Nuclear Propulsion Plant Watch Officer and Electrical Distribution Officer aboard the USS ENTERPRISE (CVN-65). He holds a BSEE from the University of Minnesota.
Merle Ashton Substation Maintenance Supervisor Tri-State G & T Association, Inc. 12496 Rd 23 Cortez CO 81321 Business: (970) 759-6139 rashton@tristategt.org	Rick Ashton is presently a Substation Maintenance Supervisor for Tri-State Generation and Transmission Assn., Inc. Rick has held this position since 2006; prior to 2006 Rick was a Substation Technician for this same company since 1981. As a Substation Technician, Rick's primary responsibility was the maintenance of Protection System components and other equipment within the substation yard and control house. Relays (protective and otherwise), batteries, transformers, circuit breakers, regulators, switches were all within his area of influence. These years of hands-on experience provided Rick opportunities to observe and investigate many different equipment failures; to use a variety of test equipment, and employ many test methods. As owner/operator of relaytech.com, Rick has authored many titles of "how-to" books that assist in the training of relay technicians. Rick travels to utilities, testing companies, and consulting firms upon request for training relay technicians, and other personnel. Rick imparts his

	overall knowledge of Protection Systems, their characteristics and interactions, as well as the math and theory behind it all, providing technical personnel with a better working understanding of the entire substation.
Forrest D. Brock Superintendent of Station Services Western Farmers Electric Cooperative 701 NE 7th Street PO Box 429 **Anadarko, Oklahoma, 73005-0429** Business: (405) 247-4360 f_brock@wfec.com	Forrest Brock is the Superintendent of Station Services at Western Farmers Electric Cooperative – a generation and transmission cooperative serving 22 distribution cooperative members in Oklahoma and New Mexico. Forrest has 23 years of protection and control experience earned through his service as a relay technician and supervisor, along with two years serving as Transmission Compliance Specialist prior to his promotion to department superintendent in 2012. In 2009, Forrest began serving as a participating and contributing observer on the Standard Drafting Team for Project 2007-17 and became an official SDT member in 2011. Forrest is also a member of the Standard Drafting Team for Project 2007-06 System Protection Coordination developing NERC Reliability Standard PRC-027-1, and represents Cooperatives as a member of the NERC System Protection and Control Subcommittee (SPCS).
Aaron Feathers Principal Engineer Pacific Gas and Electric Company 487 W. Shaw Avenue, Building A Fresno, CA 93704 Business: (559)263-5011 aaron.feathers@pge.com	Aaron Feathers is presently a Principal Engineer in System Protection at Pacific Gas and Electric Company, where he has been employed since 1992. He has 20 years of experience in the application of protective relaying and control systems on transmission systems. Aaron's current job responsibilities include design standards, wide area RAS support, NERC PRC compliance, and relay asset management support. He has a BSEE degree from California State Polytechnic University, San Luis Obispo and is a registered Professional Engineer in the State of California. He is also a member of IEEE and is on the Western Protective Relay Conference planning committee.
Samuel Francis System Protection Specialist Oncor Electric Delivery 115 W. 7th Street Suite 3114 P. O. Box 970 Fort Worth TX 76101	Samuel B. Francis is presently a System Protection Specialist for Oncor Electric Delivery. Sam has over 35 years experience working for Oncor Electric Delivery with 30 years of that time having been spent in the area of System Protection in which he has served on several taskforces and committees that have been responsible for determining maintenance and testing procedures for the Oncor Protection Systems. For the past 7 years, Mr. Francis has been a member of the NERC System Protection and Control Subcommittee (SPCS) formally the System Protection and Control

Business: (817) 215-6920 samuel.francis@oncor.com	Task Force (SPCTF). Mr. Francis is also a member of the NERC Protection System Maintenance and Testing Standard Drafting Team (PSMTSDT) developing the NERC Reliability Standard PRC-005-2. Sam has also been a member of the NERC System Protection Coordination Standard Drafting Team (SPCSDT) since its formation in 2008 developing NERC Reliability Standard PRC-027-1. Mr. Francis holds a BSEE from Brigham Young University and is a registered Professional Engineer in the State of Texas.
Ervin David Harper I & E Specialist NRG Texas Maintenance Services 12307 Kurland Houston TX 77034 Business: (713) 545-6019 david.harper@nrgenergy.com	Ervin David Harper is presently I&E specialist for NRG Maintenance Services responsible for protective system maintenance and testing and system and equipment fault analysis. He has over 30 years experience in the maintenance and testing of generation station equipment including generators, transformers, switchgear, motors and protection and control systems.
James M. Kinney Senior Engineer FirstEnergy Corporation 76 South Main Street Akron, OH 44308 Business: (419) 521-6252 kinneyj@firstenergycorp.com	James M. Kinney is presently a Senior Engineer, Transmission and Substation Services at FirstEnergy Corporation. He has over 20 years of experience in the power industry including engineering, operations and maintenance. Since 2000, he has been responsible for substation commissioning as well as substation maintenance and testing programs at FirstEnergy Corporation. He is a senior member IEEE, a member of the IEEE Power and Energy Society, an individual member of the IEEE Standards Association, and also an individual member of Cigre'. He holds a BSEE from The Ohio State University and is a registered Professional Engineer in the State of Ohio.
Mark Lukas T&S Engineering, Real Time Analysis Manager Commonwealth Edison Co. Two Lincoln Centre 9th Floor Oakbrook Terrace IL 60181-4260 Business: (630) 576-6891	Mark Lukas has worked for ComEd in various Protection and Control roles for most of his 36 years. Upon graduating from Purdue University-Calumet in 1979, early responsibilities were in the Operational Analysis (Field Testing) Department performing Substation Relay and Equipment installations, maintenance, and troubleshooting. Subsequent moves were into manager roles in various Operational Analysis sections and then managing the Relay and Protection Engineering - SCADA Standards group. Mark has currently been managing the Relay and Protection Engineering - Real Time Analysis group for 12 years. Mark's current

mark.lukas@comed.com	duties/responsibilities include 7x24 operational analysis support for Transmission & Substation automatic operations, abnormal system configuration evaluations, as well as abnormal protection system conditions evaluations.
Jordan Mallory Standards Developer Speciliast NERC 3353 Peachtree Rd. NE Atlanta, GA 30326 Business (404) 456-4473 Jordan.mallory@nerc.net	Jordan Mallory is a Standards Developer Specalist for NERC. Ms. Mallory successfully lead the PER-005-2 Standards Drafting Team from a process of many years to a one year completion. Prior to joining NERC in 2011, Ms. Mallory worked at MEAG Power for three years. Jordan holds a Business Degree in Managerial Science from Georgia State University.
Kristina Marriott Senior Project Manager & Application Consultant ENOSERV 7708 East 106th Street Tulsa, Ok 74133 Business: (918) 622-4530 x 110 kmarriott@enoserv.com	Kristina Marriott has been the Senior Project Manager at ENOSERV for over 3 years and has worked for ENOSERV over 5. Her primary job consists of consulting & data application projects. Many of her projects have been geared to Transmission and Distribution, where she works with Engineering and Technical groups to develop, implement, and support maintenance Programs for Protection System components and other equipment utilizing multiple systems & applications. Prior to her Project Manager position, she supported multiple utilities in troubleshooting and maintaining Protective Relays. She has extensive knowledge and experience with asset management, business plans, policies, regulatory compliance, and continues to take an extreme interest in Protection and Control.
Al McMeekin Standards Development Advisor NERC 3353 Peachtree Rd. NE Suite 600, North Tower Atlanta, GA 30326 Business (803) 530-1963 al.mcmeekin@nerc.net	Al McMeekin is a Standards Developer for NERC. Prior to joining NERC in 2009, Mr. McMeekin worked at South Carolina Electric & Gas Company (SCE&G) for 29 years holding a variety of professional and supervisory positions within the distribution and transmission organizations. Al participated in SCE&G's ERO Working Group to ensure compliance with NERC standards; and represented SCE&G on various national, regional, and sub-regional groups. Mr. McMeekin was a member of the SERC Operating Committee and served as Chair of the SERC Operations Planning Subcommittee. Al was a member of the SERC Standards Committee and the SERC Available Transfer Capability Working Group. He also served as Chair of the VACAR South Reliability Coordinator Procedures

	Working Group, and was a member of Project 2006-03 (System Restoration and Blackstart – EOP-005 & EOP-006) Standards Drafting Team. Al holds a BSAgE degree from Clemson University and is a registered Professional Engineer in South Carolina.
Michael Palusso Manager Transmission/Substation FERC/NERC/CAISO/CPUC Compliance Southern California Edison (SCE) 3 Innovation Way Pomona, CA, 91768 Business: (909) 274-3460 Michael.Palusso@sce.com	Mike Palusso has been part of the Southern California Edison company for 30 years. Throughout his career Mike held numerous positions in the substation area culminating as the Manager for Power Utility Substation Equipment and Relay. Mike is currently the Manager for Transmission/Substation Maintenance & Inspection Compliance. His responsibilities encompass compliance for NERC/WECC/CAISO, as well as CPUC compliance reporting for protection and control systems, substation equipment, vegetation management, and transmission line equipment. Mike also represents SCE's interests on the CAISO Transmission Maintenance Coordination Committee.
Charles W. Rogers Principal Engineer Consumers Energy 1945 W. Parnall Road Jackson, Michigan 49201 Business: (517) 788-0027 Charles.Rogers@cmsenergy.com	Charles Rogers is a Principal Engineer at Consumers Energy, where he has been employed since 1978. For the bulk of his career, has been responsible for application of protective relaying to the transmission and distribution systems, and is currently responsible for managing compliance to NERC Standards for the "wires" portion of Consumers Energy. He chaired the NERC System Protection and Control Task Force from its inception in 2004 through May 2008, and continues to be a member of its successor group, the NERC System Protection and Control Task Force, and was a member of the NERC Planning Committee in 2009. He chaired the ECAR investigation into the August 2003 blackout, chaired the ECAR Protection Panel for several years, and chaired the RFC Protection Subcommittee from its inception in 2006 through 2012. At NERC, he was a member of the "Phase II Standard Drafting Team" in 2005-2006, chaired the standard drafting team that developed PRC-023-1, and currently chairs the standard drafting teams assigned to Projects 2007-17 (Protection System Maintenance) and 2010-13 (addressing FERC Order 733). At RFC, he also chaired the standard drafting team that developed PRC-002-RFC. Charles is also a member of IEEE Standards Coordinating Committee 21, and was a key member of the working groups that developed IEEE 1547, IEEE 1547.2, and IEEE 1547.4. He received his BSEE degree from Michigan Technological University in 1978. He is a registered professional engineer in the State of Michigan, and is a Senior Member of IEEE.

John E. Schechter Manager, Protection & Control Engineering Office American Electric Power 700 Morrison Road Gahanna OH 43230 (614) 552-1908 jeschechter@aep.com	John Schechter is Manager of American Electric Power's Protection & Control Engineering office in Columbus, Ohio. John has been with American Electric Power (AEP) or its operating companies since 1980. He has held many positions with increasing responsibility in substation operation, construction, maintenance or engineering spanning 32 years and has also held supervisory or managerial positions in distribution line design, distribution service dispatching, overhead and underground distribution maintenance and construction, and transmission line asset management. Following the 2003 blackout, John was named to the NERC Transmission Vegetation Management (VM) task force to draft the new vegetation management standard. He was named to the NERC PRC-005-2 revision drafting team in 2011. John received the B.S.E.E. degree in electrical engineering from the University of Cincinnati, the M.S.E.E. degree in electric power systems engineering from The Ohio State University, and the M.B.A. degree from the University of Notre Dame. He is a registered professional engineer in the states of Indiana and Ohio.
William D. Shultz Engineering Manager Southern Company Generation 42 Inverness Center Parkway Mail Bin B425 Birmingham AL 35242 Business: (205) 992-5526 wdshultz@southernco.com	Bill Shultz is presently Engineering Manager, Electrical Services and Field Support, Technical Services of Southern Company Generation. He has 29 years of experience in Generating Plant Technical Services, including protective equipment application, start-up commissioning, and maintenance of protective relaying and control systems for electric power generating plants. His work experience includes the commissioning and maintenance of the control and protection of static excitation systems, variable speed drives, and emergency generation. He is active in Southern Company reliability standards compliance efforts as well as being involved in regional and national organizations responsible for utility reliability standards. He holds a BSEE from the University of Tennessee, a MSEE from Auburn University, and is a registered Professional Engineer in the State of Alabama.
Eric Udren Executive Advisor Quanta Technology, LLC 1395 Terrace Drive Pittsburgh, PA 15228	Eric A. Udren has a 43 year distinguished career in design and application of protective relaying, utility substation control, and communications systems. He developed protection software for the world's first computer based transmission line relaying system, as well as for the world's first substation P&C system based on local area network communications. He has worked with major utilities to develop new substation protection, control, data

Business: (412)-596-6959 eudren@quanta-technology.com	communications, SPS, and wide area monitoring and protection system designs, including major projects for substation integration based on IEC 61850. He currently serves as Executive Advisor with Quanta Technology, LLC of Raleigh, NC with his office in Pittsburgh, PA. Eric is IEEE Fellow, Chair of the Relaying Communications Subcommittee of the IEEE Power System Relaying Committee (PSRC) and chairs two standards working groups of PSRC. He is Technical Advisor to the US National Committee of IEC for protective relay standards from TC 95; and is member of the IEC TC 57 WG 10 that develops IEC 61850 power systems communications and integration protocol. Eric serves on the NERC System Protection and Control Subcommittee (SPCS), as well as the subject PRC-005-2 Drafting Team. He has written and presented over 90 technical papers and book chapters.
Scott Vaughan, P.E. Electrical Engineering Manager Roseville Electric 2090 Hilltop Circle Roseville, CA 95747 Business: (916) 774-5604 svaughan@roseville.ca.us	Scott Vaughan is currently the Electrical Engineering Manager of Roseville Electric. He has over 18 years of industry experience. In his current position, Mr. Vaughan is responsible for the operation, design and construction of electrical facilities within the City of Roseville. Throughout his career, he has held positions as a protection, generation facility design, and substation design engineer. He has worked as the Subject Matter Expert (SME) for Roseville Electric since 2007 and is currently the responsible engineer for compliance with the NERC mandatory reliability standards relating to the city's registration as a Distribution Provider, Generator Operator and Generator Owner. Mr. Vaughan holds a BSEE from the California Polytechnical State University at San Luis Obispo, a MBA from Golden Gate University and is a registered engineer in the State of California.
Mathew J. Westrich, P.E. Assistant Manager Asset Maintenance American Transmission Co. (ATC) Business: 906-779-7901 mwestrich@atcllc.com	Mathew Westrich is presently the Assistant Manager Asset Maintenance for American Transmission Company. Previously Matt held positions as Substation Maintenance Engineer and Asset Manager with ATC. He also worked for Wisconsin Energies as a relay testing technician since 1982. He has over 30 years' experience in Protection, Commissioning and Maintenance. He is a licensed P.E. with the State of Wisconsin.
Philip B. Winston	Philip B. Winston is presently the Chief Engineer, Protection and Control Applications for Southern Company Transmission.

Chief Engineer, Protection and Control Applications Southern Company 62 Like Mirror Road Bin # 50061 Forest Park, Georgia 30297 Business: (404) 608-5989 pbwinsto@southernco.com	Previously he was the Manager, Protection and Control Applications with Georgia Power Company since 1991. With over 42 years' experience in Protection, Operations, Engineering, and Maintenance, he has been active in Southern Company standardization efforts as well as being involved in regional and national organizations responsible for utility standards and disturbance analysis. He is a past Chairman of the IEEE/Power System Relaying Committee, a past Chair of the PSRC Systems Protection and the Line Protection Subcommittees, presently the Standards Coordinator for IEEE PSRC and serves on the IEEE Standards Association Standards Board, NesCom (chair), and ProCom. He is the Chair of the NERC SPCS, and serves on several NERC Standard Drafting Teams including the Chair of Project 2007-06 System Protection Coordination SDT. He holds a BSEE from Clemson University, a MSEE from Georgia Tech, and is a registered Professional Engineer in the State of Georgia.
John Zipp Senior Staff Engineer ITC Holdings 27175 Energy Way Novi MI 48377 Business: (248) 946-3289 jzipp@itctransco.com	John Zipp has over 30 years of transmission system protection experience. He has 27 years of experience at Consumers Energy in the System Protection area. He spent 20 years as the supervisor of the Transmission System protection group directing protection system design, setting, and managing the protective system maintenance program at Consumers Energy. He was System Control Supervisor for 4 years directing the south control room in Jackson Michigan. He is presently a Senior Staff engineer at ITC Holdings directing the Relay Engineering department since 2007. He is an IEEE Senior member and was a member of the Power System Relaying Technical Committee in the IEEE for 17 years serving many working groups and as the Chair of the Line Protection committee. He has a BSEE degree from Michigan Tech and is a Registered professional Engineer in the State of Michigan.