Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard is adopted by the NERC Board of Trustees (Board).

Description of Current Draft

Completed Actions	Date
Standards Committee approved Standard Authorization Request (SAR) for posting	June 26, 2019
SAR posted for comment	July 30, 2019-August 28, 2019

Anticipated Actions	Date
45-day formal comment period with ballot	May 25, 2023 – July 10, 2023
45-day formal comment period with additional ballot	TBD
10-day final ballot	TBD
Board adoption	TBD

New or Modified Term(s) Used in NERC Reliability Standards

This section includes all new or modified terms used in the proposed standard that will be included in the *Glossary of Terms Used in NERC Reliability Standards* upon applicable regulatory approval. Terms used in the proposed standard that are already defined and are not being modified can be found in the *Glossary of Terms Used in NERC Reliability Standards*. The new or revised terms listed below will be presented for approval with the proposed standard. Upon Board adoption, this section will be removed.

Term(s):

The PRC-005-7 Standard Drafting Team (SDT) proposes to modify the NERC Glossary of Terms definition of **Protection System**:

Protection System – One or more of the following components:

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

This term is also used in other standards, as indicated below. The PRC-005-7 SDT is obligated to review other standards in which this term is used to determine if reliability gaps or redundancies are created by the proposed revision to the defined term. The PRC-005-7 SDT has determined that the proposed modified definition does not change the reliability intent of other requirements or definitions.

The Protection System definition was changed to ensure uniformity among all reliability standards. Components of control systems which respond to measured electrical quantities and provide protective functions provide the same functionality, and thereby present the same risk, to the Bulk Electric System as protective relays. The risk of such components has already been realized and addressed in certain standards (PRC-019 and PRC-24, for instance), but it is crucial that these devices be uniformly accepted for their functionality and risk to the Bulk Electric System in terms of configuration, physical and cyber security, operation, and redundancy.

Additionally, it is important to maintain reliability standards that are technology neutral and centered around risk to the Bulk Electric System. The previous definition of Protection System provided requirements for a specific technology (protective relays) and left ambiguity regarding these other devices which perform the same function. Likewise, to only address synchronous generator excitation systems is again focusing on a specific technology and not the risk to the

Bulk Electric System. It is for these reasons that these devices should be treated as components of a Protection System among all reliability standards to ensure not only that they are maintained, but that they are designed, configured, protected, and studied in a manner consistent with protective relays which provide the same functionality.

The proposed revisions to **Protection System** are intended to provide clarity on the inclusion of Components of control systems which measure and utilize similar quantities as protective relays and perform similar functions as protective relays.

- CIP-002-5.1a – BES Cyber System Categorization
- CIP-003-8 – Cyber Security – Security Management Controls
- CIP-005-6 – Cyber Security – Electronic Security Perimeter(s)
- CIP-005-7 – Cyber Security – Electronic Security Perimeter(s)
- CIP-006-6 – Cyber Security – Physical Security of BES Cyber Systems
- CIP-007-6 – Cyber Security – Systems Security Management
- CIP-008-6 – Cyber Security – Incident Reporting and Response Planning
- CIP-009-6 – Cyber Security – Recovery Plans for BES Cyber Systems
- CIP-010-3 – Cyber Security – Configuration Change Management and Vulnerability Assessments
- CIP-010-4 – Cyber Security – Configuration Change Management and Vulnerability Assessments
- CIP-011-2 – Cyber Security – Information Protection
- CIP-013-2 – Cyber Security – Supply Chain Risk Management
- EOP-010-1 – Geomagnetic Disturbance Operations (in background section)
- IRO-010-2 – Reliability Coordinator Data Specification and Collection
- IRO-010-3 – Reliability Coordinator Data Specification and Collection
- PER-005-2 – Operations Personnel Training
- PER-006-1 – Specific Training for Personnel
- PRC-004-6 – Protection System Misoperation Identification and Correction
- PRC-012-2 – Remedial Action Schemes
- PRC-017-1 – Remedial Action Scheme Maintenance and Testing
- PRC-019-2 – Coordination of Generating Unit or Plant Capabilities, Voltage Regulating Controls, and Protection
- PRC-023-4 – Transmission Relay Loadability
- PRC-024-3 – Frequency and Voltage Protection Settings for Generating Resources
- PRC-025-2 – Generator Relay Loadability
- PRC-026-1 – Relay Performance During Stable Power Swings
- PRC-027-1 – Coordination of Protection Systems for Performance During Faults
- TOP-003-4 – Operational Reliability Data
- TPL-001-4 – Transmission System Planning Performance Requirements
- TPL-001-5.1 – Transmission System Planning Performance Requirements

- TPL-007-4 – Transmission System Planned Performance for Geomagnetic Disturbance Events

A. Introduction

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

2. **Number:** **PRC-005-7**

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

4.1.4. UFLS-Only 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, except for generators identified through Inclusion I4 of the BES definition, 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 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. Protection Systems and Sudden Pressure Relaying for the following BES generator Facilities for dispersed power producing resources identified through Inclusion I4 of the BES definition:

4.2.6.1. Protection Systems and Sudden Pressure Relaying for Facilities used in aggregating dispersed BES generation from the point where those resources aggregate to greater than 75 MVA to a common point of connection at 100kV or above.

4.2.7. Automatic Reclosing[1], including:

4.2.7.1. 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]

4.2.7.2. Automatic Reclosing applied on the terminals of all BES Elements at substations one bus away from generating plants specified in Section 4.2.7.1 when the substation is less than 10 circuit-miles from the generating plant substation.

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

5. **Effective Date:** See Implementation Plan for PRC-005-7.
6. **Definitions Used in this Standard:**

Automatic Reclosing – Includes the following Components:

- Reclosing relay
- Supervisory relay(s) or function(s) – relay(s) or function(s) that perform voltage and/or sync check functions that enable or disable operation of the reclosing relay

[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 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.

- Voltage sensing devices associated with the supervisory relay(s) or function(s)
- Control circuitry associated with the reclosing relay or supervisory relay(s) or function(s)

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 four 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 4-3, 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, Distribution Provider, and UFLS-only 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, non-battery based energy storage and alternative electro-chemical based energy storage 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 4-3, 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, Distribution Provider and UFLS-only Distribution Provider shall have a documented PSMP 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, non-battery based energy storage associated with the 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 4-3, and Table 5. (Part 1.2).

R2. Each Transmission Owner, Generator Owner, Distribution Provider and UFLS-only 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, Distribution Provider and UFLS-only 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, Distribution Provider and UFLS-only 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 4-3, and Table 5. *[Violation Risk Factor: High] [Time Horizon: Operations Planning]*

M3. Each Transmission Owner, Generator Owner, Distribution Provider and UFLS-only 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, Distribution Provider and UFLS-only 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, Distribution Provider and UFLS-only Distribution Provider that utilizes performance-based maintenance intervals in accordance with Requirement R2 shall have evidence that it has implemented the PSMP 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, Distribution Provider and UFLS-only 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, Distribution Provider and UFLS-only 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: "Compliance Enforcement Authority" means NERC or the Regional Entity, or any entity as otherwise designated by an Applicable Governmental Authority, in their respective roles of monitoring and/or enforcing compliance with mandatory and enforceable Reliability Standards in their respective jurisdictions.

1.2. Evidence Retention The following evidence retention period(s) 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 applicable entity shall 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, Distribution Provider and UFLS-only Distribution Provider shall each keep its current dated PSMP, 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, Distribution Provider and UFLS-only 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, Distribution Provider and UFLS-only 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.

1.3. Compliance Monitoring and Enforcement Program: As defined in the NERC Rules of Procedure, "Compliance Monitoring and Enforcement Program" refers to the identification of the processes that will be used to evaluate data or information for the purpose of assessing performance or outcomes with the associated Reliability Standard.

Violation Severity Levels

R #	Violation Severity Levels			
	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 4-3, 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, non-battery based energy storage, or alternative electro-chemical based energy storage associated with the dc supply Component Types 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	N/A	The entity uses performance-based maintenance intervals in its PSMP but failed to reduce Countable Events to no	The entity uses performance-based maintenance intervals in its PSMP but:

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
	more than 4% within three years.		more than 4% within four years.	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

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
				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 4-3, 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 4-3, 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 4-3, 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 4-3, and Table 5.
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	For Components included within a performance-based maintenance program, the entity failed to maintain more than 5% but 10% or less of the	For Components included within a performance-based maintenance program, the entity failed to maintain more than 10% but 15% or less of	For Components included within a performance-based maintenance program, the entity failed to maintain more than 15% of the annual

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
	Component Type in accordance with their performance-based PSMP.	annual scheduled maintenance for a specific Component Type in accordance with their performance-based PSMP.	the annual scheduled maintenance for a specific Component Type in accordance with their performance-based PSMP.	scheduled maintenance for a specific Component Type in accordance with their performance-based PSMP.
R5.	The entity failed to undertake efforts to correct five (5) or fewer identified Unresolved Maintenance Issues.	The entity failed to undertake efforts to correct greater than five (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. Associated 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-005-7 Protection System Maintenance,* Protection System Maintenance and Testing Standard Drafting Team (March 2023)
2. Technical Rationale for Modification of Protection System Definition (March 2023)
3. *Considerations for Maintenance and Testing of Auto-reclosing Schemes*, NERC System Analysis and Modeling Subcommittee, and NERC System Protection and Control Subcommittee (November 2012)

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
1	March 16, 2007	PRC-005-1 Approved by FERC, Docket No. RMO6-16-000	
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
1a	September 26, 2011	Approved by FERC. Docket No. RD11-5-000	
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).
1b	February 3, 2012	PRC-005-1b Approved by FERC. Docket No. RM10-5-000	
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.

Version	Date	Action	Change Tracking
1.1b	September 19, 2013	PRC-005-1.1b Approved by FERC. Docket No. RM12-16-000	Project 2007-17 - Complete revision, absorbing maintenance requirements from PRC-005-1.1b, PRC-008-0, PRC-011-0, PRC-017-0
2	November 7, 2012	Adopted by NERC Board of Trustees	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	October 17, 2013	Approved by NERC Standards Committee	
2	December 19, 2013	PRC-005-2 Approved by FERC. Docket No. RM13-7-000	Modified R1 VSL in response to FERC directive (no change to standard version number)
2	March 7, 2014	Adopted by NERC Board of Trustees	
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
2(i)	May 29, 2015	PRC-005-2(i) Approved by FERC. Docket No. RD15-3-000	
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

Version	Date	Action	Change Tracking
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	January 22, 2015	PRC-005-3 Approved by FERC. Docket No. RM14-8-000	
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(i)	May 29, 2015	PRC-005-3(i) Approved by FERC. Docket No. RD15-3-000	
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
4	Sept 17, 2015	PRC-005-4 Approved by FERC. Docket No. RM15-9-000	
5	May 7, 2015	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
6	November 5, 2015	Adopted by NERC Board of Trustees	Revised to add supervisory relays, the voltage sensing devices, and the associated control circuitry to Automatic Reclosing in accordance with the directives in FERC Order 803.
6	December 18, 2015	FERC Letter Order approving PRC-005-6. Docket No. RD16-2-000.	
7	TBD	Adopted by NERC Board of Trustees	

<table>
<tr><th colspan="3">Table 1-1
Component Type - Protective relays and Components of control systems which respond to measured electrical quantities and provide protective functions
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/Component not having all the monitoring attributes of a category below.</td><td>6 Calendar Years</td><td>For all unmonitored relays/Components:
• Verify that protective function settings are as specified.
For non-microprocessor relays/Components:
• Test and, if necessary calibrate.
For microprocessor relays/Components:
• Verify operation of the relay/Component inputs and outputs that are essential to proper functioning of the Protection System.
• Verify acceptable measurement of power system input values that are essential to proper functioning of the Protection System.</td></tr>
<tr><td>Monitored microprocessor protective relay/Component 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:
• Protective function settings are as specified.
• Operation of the relay/Component inputs and outputs that are essential to proper functioning of the Protection System.
• Acceptable measurement of power system input values that are essential to proper functioning of the Protection System.</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.

Table 1-1 Component Type - Protective relays and Components of control systems which respond to measured electrical quantities and provide protective functions Excluding distributed UFLS and distributed UVLS (see Table 3)		
Component Attributes	**Maximum Maintenance Interval**[3]	**Maintenance Activities**
Monitored microprocessor protective relay/Component 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/Component 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 necessary for the correct operation of protective functions 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 relay or Components of control system.
Voltage and Current Sensing devices connected to microprocessor relays/control system Components with ac measurements that are continuously verified by comparison of sensing input values 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>
<tr><th colspan="3">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)).</th></tr>
<tr><th>Component Attributes</th><th>Maximum Maintenance Interval</th><th>Maintenance Activities</th></tr>
<tr><td rowspan="3">Protection System Station dc supply with Valve Regulated Lead-Acid (VRLA) batteries not having monitoring attributes of Table 1-4(f).</td><td>4 Calendar Months</td><td>Verify:
• Station dc supply voltage.
Inspect:
• For unintentional grounds.</td></tr>
<tr><td>6 Calendar Months</td><td>Inspect:
• Condition of all individual units by measuring battery cell/unit internal ohmic values.</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:
• Physical condition of battery rack.</td></tr>
</table>

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.
	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 or output voltage monitoring and alarming to ensure correct float or output voltage is being applied on the station dc supply (See Table 2).		No periodic verification of float voltage or output voltage monitoring 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 alternative electro-chemical based energy storage station dc supply with monitoring and alarming of battery string(s) 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 alternative electro-chemical based energy storage station dc supply with monitoring and alarming of integrity of all battery electrical connections (See Table 2).		No periodic verification of the battery continuity is required.

Table 1-4(f) Exclusions for Protection System Station dc Supply Monitoring Devices and Systems		
Component Attributes	**Maximum Maintenance Interval**	**Maintenance Activities**
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.
Any alternative electro-chemical based energy storage with monitoring and alarming that it can perform as manufactured (See Table 2).		No periodic evaluation relative to baseline capacity indicative of battery performance is required to verify the station battery can perform as manufactured.

Table 1-4(g) Component Type – Protection System Station dc Supply Using Alternative Electro-chemical 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**
Protection System station dc supply with alternative electro-chemical based energy storage not having monitoring attributes of Table 1-4(f).	4 Calendar Months	Verify: • Station dc supply voltage. Inspect: • For unintentional grounds.
	18 Calendar Months	Verify: • Output voltage of battery charger. • Battery continuity. • Integrity of all battery electrical connections. Inspect: • Condition of alternative electro-chemical based energy storage station dc supply. • Physical condition of battery rack/cabinet/enclosure.
	1/3 of estimated lifetime (maximum of 6 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 1-5 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 or Component of control system 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 4-3, 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 4-3, 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/Component not having all the monitoring attributes of a category below.	6 Calendar Years	Verify that settings are as specified. For non-microprocessor relays/Components: • Test and, if necessary, calibrate. For microprocessor relays/Components: • Verify operation of the inputs and outputs that are essential to proper functioning of the Protection System. • Verify acceptable measurement of power system input values that are essential to proper functioning of the Protection System.
Monitored microprocessor protective relay/Component 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: • Protective function settings are as specified. • Operation of the inputs and outputs that are essential to proper functioning of the Protection System. • Acceptable measurement of power system input values that are essential to proper functioning of the Protection System.
Monitored microprocessor protective relay/Component 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 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**
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/Components.
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 device and electromechanical lockout and/or tripping auxiliary devices (excludes non-BES interrupting device trip coils).	12 Calendar Years	Verify the path from the device 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 devices (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 and Supervisory Relay Note: In cases where Components of Automatic Reclosing are common to Components listed in Table 1-1 through 1-5, the Components only need to be tested once during a distinct maintenance interval.		
Component Attributes	**Maximum Maintenance Interval**	**Maintenance Activities**
Any unmonitored reclosing relay or supervisory relay not having all the monitoring attributes of a category below.	6 Calendar Years	Verify that settings are as specified. For non-microprocessor reclosing or supervisory relays: • Test and, if necessary calibrate. For microprocessor reclosing or supervisory relays: • Verify operation of the relay inputs and outputs that are essential to proper functioning of the Automatic Reclosing. For microprocessor supervisory relays: • Verify acceptable measurement of power system input values.
• Monitored microprocessor reclosing relay or supervisory relay with the following: Internal self-diagnosis and alarming (See Table 2). • Alarming for power supply failure (See Table 2). For supervisory relay: • Voltage waveform sampling three or more times per power cycle, and conversion of samples to numeric values for measurement calculations by microprocessor electronics.	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. For supervisory relays: • Verify acceptable measurement of power system input values.
Monitored microprocessor reclosing relay or supervisory relay with preceding row attributes and the following:	12 Calendar Years	Verify only the unmonitored relay inputs and outputs that are essential to proper functioning of the Automatic Reclosing.

Table 4-1 Maintenance Activities and Intervals for Automatic Reclosing Components Component Type – Reclosing and Supervisory Relay Note: In cases where Components of Automatic Reclosing are common to Components listed in Table 1-1 through 1-5, the Components only need to be tested once during a distinct maintenance interval.		
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). For supervisory relay: • Ac measurements are continuously verified by comparison to an independent ac measurement source, with alarming for excessive error (See Table 2).		

Table 4-2(a) Maintenance Activities and Intervals for Automatic Reclosing Components Component Type – Control Circuitry Associated with Reclosing and Supervisory Relays that are NOT an Integral Part of an RAS Note: In cases where Components of Automatic Reclosing 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**
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 and Supervisory Relays that ARE an Integral Part of an RAS Note: In cases where Components of Automatic Reclosing 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**
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 4-3 Maintenance Activities and Intervals for Automatic Reclosing Components Component Type – Voltage Sensing Devices Associated with Supervisory Relays Note: In cases where Components of Automatic Reclosing are common to Components listed in Table 1-3, the Components only need to be tested once during a distinct maintenance interval.		
Component Attributes	**Maximum Maintenance Interval**	**Maintenance Activities**
Any voltage sensing devices not having monitoring attributes of the category below.	12 Calendar Years	Verify that voltage signal values are provided to the supervisory relays.
Voltage sensing devices that are connected to microprocessor supervisory relays with ac measurements that 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 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-005-7 – 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 4-3, 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.